UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31 , 2023
Commission File Number: 001-35467

Battalion Oil Corp oration
(Exact name of registrant as specified in its charter)

Delaware	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

820 Gessner Road , Suite 1100 , Houston , TX 77024
(Address of principal executive offices)

(832) 538-0300
(Registrant's telephone number)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock par value $0.0001	BATL	NYSE American

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☒
			Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

As of March 25, 2024, there were 16,456,563 shares outstanding of registrant's $.0001 par value common stock. Based upon the closing price for the registrant's common stock on the New York Stock Exchange as of June 30, 2023, the aggregate market value of shares of common stock held by non-affiliates of the registrant was approximately $ 21.9 million.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities made under a plan confirmed by a court. Yes ☒ No ☐

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13, and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2024 annual meeting of stockholders which will be filed no later than 120 days after December 31, 2023.

TABLE OF CONTENTS

Special note regarding forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, may be forward-looking statements, should be evaluated as such and may concern, among other things, the structure, timing and completion of the proposed Merger (as defined below); any anticipated effects of the announcement, pendency or completion of the proposed Merger on the value of our common stock; ability to obtain any required regulatory approvals in connection with the proposed Merger; expenses related to the proposed Merger and any potential future costs; planned capital expenditures, potential increases in oil and natural gas production, potential costs to be incurred, future cash flows and borrowings, our financial position, business strategy and other plans and objectives for future operations. These forward-looking statements may be identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “objective,” “believe,” “predict,” “intend,” “achievable,” “anticipate,” “will,” “continue,” “potential,” “should,” “could” and similar terms and phrases. Although we believe that the expectations reflected in forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. Readers should consider carefully the risks described under the “Risk Factors” section of this report and other sections of this report which describe factors that could cause our actual results to differ from those anticipated in forward-looking statements, which include, but are not limited to, the following factors:

- volatility in prices for oil, natural gas and natural gas liquids;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and develop our undeveloped acreage positions;
- contractual limitations that affect our management’s discretion in managing our business, including covenants that, among other things, limit our ability to incur debt, make investments and pay cash dividends;
- our indebtedness, which may increase in the future, and higher levels of indebtedness can make us more vulnerable to economic downturns and adverse developments in our business;
- our ability to replace our oil and natural gas reserves and production;
- the presence or recoverability of estimated oil and natural gas reserves attributable to our properties and the actual future production rates and associated costs of producing those oil and natural gas reserves;
- our ability to successfully develop our large inventory of undeveloped acreage;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars, which may be subject to inflation caused by labor shortages, supply shortages and increased demand, and other inflationary pressures
- our ability to secure adequate sour gas treating and/or sour gas take-away capacity, including the acid gas treatment facility for our Monument Draw area attaining targeted production volumes and costs in treating our sour gas;
- drilling and operating risks, including accidents, equipment failures, fires, and releases of toxic or hazardous materials, such as hydrogen sulfide (H_2S), which can result in injury, loss of life, pollution, property damage and suspension of operations;
- senior management’s ability to execute our plans to meet our goals;
- access to and availability of water, sand and other treatment materials to carry out fracture stimulations in our completion operations;
- the possibility that our industry may be subject to future regulatory or legislative actions (including, but not limited to, additional taxes and changes in environmental regulations);
- access to adequate gathering systems, processing and treating facilities and transportation take-away capacity to move our production to marketing outlets to sell our production at market prices;
- our ability to pursue and integrate strategic mergers and acquisitions;
- the potential for production decline rates for our wells to be greater than we expect;
- competition, including competition for acreage in our resource play;
- environmental risks, such as accidental spills of toxic or hazardous materials, and the potential for environmental liabilities;
- exploration and development risks;
- our ability to retain key members of senior management, the board of directors and key technical employees;

- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as the conflict between Ukraine and Russia, and acts of terrorism or sabotage;
- impacts of climate regulations;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;
- impacts and potential risks related to actual or anticipated pandemics, including any associated impact to our operations, financial results, liquidity, contractors, customers, employees and vendors;
- impacts and potential risks of extreme weather;
- other economic, competitive, governmental, regulatory, legislative, including federal and state regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;
- our insurance coverage may not adequately cover all losses that we may sustain; and
- title to the properties in which we have an interest which may be impaired by title defects.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Glossary of Oil and Natural Gas Terms

The definitions set forth below apply to the indicated terms as used in this report. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of one-pound of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed property. Property where wells have been drilled and production equipment has been installed.

Development well. A well drilled within the proved areas of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Extension well. A well drilled to extend the limits of a known reservoir.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Hydraulic fracturing. The injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production.

H2S. Hydrogen sulfide, a colorless, flammable and extremely hazardous naturally occurring gas that is sometimes produced from oil and natural gas wells.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million Boe.

MMBtu. One million Btu.

MMcf. One million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NGLs. Natural gas liquids, i.e. hydrocarbons removed as a liquid, such as ethane, propane and butane.

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.

Proved developed reserves. Proved reserves that are expected to be recovered from existing wellbores, whether or not currently producing, without drilling additional wells. Production of such reserves may require a recompletion.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has been previously completed.

Reserve-to-production ratio or Reserve life. A ratio determined by dividing estimated existing reserves determined as of the stated measurement date by production from such reserves for the prior twelve month period.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Spud. Commencement of actual drilling operations.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

PART I

ITEM 1. BUSINESS

Overview

Unless the context otherwise requires, all references in this report to “Battalion,”, “the Company”, “our,” “us,” and “we” refer to Battalion Oil Corporation and its subsidiaries, as a common entity. Battalion is the successor reporting company to Halcón Resources Corporation (“Halcón”). On January 21, 2020, we filed a Certificate of Amendment to our Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to effect a change of our corporate name from Halcón Resources Corporation to Battalion Oil Corporation.

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. Our properties and drilling activities are currently focused in the Delaware Basin, where we have an extensive drilling inventory that we believe offers attractive long-term economics.

Our working interests in 39,867 net acres in the Delaware Basin as of December 31, 2023 are in Pecos, Reeves, Ward and Winkler Counties, Texas. This resource play is characterized by high oil and liquids-rich natural gas content in thick, continuous sections of source rock that can provide repeatable drilling opportunities and significant initial production rates. Our primary targets in this area are the Wolfcamp and Bone Spring formations. As of December 31, 2023, we had 90 operated wells producing in this area in addition to minor working interests in 19 non-operated wells. Our average daily net production from this area for the year ended December 31, 2023 was 13,784 Boe/d.

At December 31, 2023, our estimated total proved oil and natural gas reserves were approximately 68.1 MMBoe, consisting of 34.6 MMBbls of oil, 14.9 MMBbls of NGLs and 111.7 Bcf of natural gas, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (“NSAI”). Reserves were prepared using a crude oil price of West Texas Intermediate (“WTI”) of $78.21 per Bbl and a Henry Hub natural gas price of $2.64 per MMBtu, based on the preceding 12-month first day of the month average spot prices as required by the Securities and Exchange Commission (the “SEC”). Approximately 59% of our estimated proved reserves were classified as proved developed and we maintain operational control of 99.9% of our estimated proved reserves as of December 31, 2023.

Business Strategy

Our primary long-term objective is to increase stockholder value by safely and cost-effectively increasing our production of oil, natural gas and NGLs, adding to our proved reserves and growing our inventory of economic drilling locations, while acting as a responsible corporate citizen in the communities in which we operate. To accomplish this objective, we intend to execute the following business strategies:

- ***Develop our Liquids-Rich Acreage Positions to Grow Production and Reserves Efficiently.*** We intend to drill and develop our multi-zone resource play to maximize value and resource potential. Our near-term development plans are focused on acreage preservation primarily in our liquids-rich Monument Draw area, maintaining production levels, and developing through the drilling and completion of new wells.

- ***Enhance Returns Through Continued Improvements in Operational and Cost Efficiencies.*** We are the operator for substantially all of our acreage, which gives us control, to some extent, over the timing of capital expenditures, execution and costs. It also allows us to adjust our capital spending based on drilling results and the economic environment. As operator, we are able to evaluate industry drilling results and implement improved operating practices that may enhance our initial production rates, ultimate recovery factors and rate of return on invested capital. We continue to focus on cost-saving measures including reducing corporate administrative expenses and pursuing operational efficiencies.

- ***Maintain Adequate Liquidity.*** Our management team is focused on maintaining adequate liquidity while pursuing our near-term development plans. We believe our internally-generated cash flows from operations, cash on hand, and preferred equity funding and commitments during 2023 as further described below will provide us with sufficient liquidity to execute our capital and operating program over the next twelve months, address near-term debt maturities of approximately $50.1 million in 2024, and maintain compliance with our debt covenants. We also employ a hedging program to reduce the variability of our cash flows used to support our capital spending. As of December 31, 2023, we have no additional borrowing capacity under our current Amended Term Loan Agreement, and as such, we will continue to pursue additional sources of liquidity and cost-saving opportunities further described in Item 7, *Management's Discussion and Analysis, "Capital Resources and Liquidity".*

- ***Attain Growth Through Strategic Business Combinations.*** From time to time, we may pursue merger and acquisition opportunities to meet our strategic and financial targets, including the maintenance of a conservative leverage position. Selective business combinations provide opportunities to acquire high quality assets complementary to our acreage, expand our drilling inventory and gain operational scale. We believe our management team's geologic and engineering expertise, particularly in the Permian Basin, provides a competitive advantage in the identification of acquisition targets and evaluation of resource potential.

Our ability to achieve our business strategy is subject to numerous risks and uncertainties, many of which are beyond our control. Additional information regarding our risks can be found in Item 1A. *Risk Factors.*

Recent Developments

- ***Merger with Fury Resources.*** On December 14, 2023, we entered into an Agreement and Plan of Merger (the "Merger Agreement") with Fury Resources, Inc. ("Parent") and San Jacinto Merger Sub, Inc ("Merger Sub"), a direct wholly-owned subsidiary of Parent, pursuant to which Parent will acquire all of the outstanding shares of common stock of the Company for $9.80 per share in cash, which represents a total transaction value of approximately $450.0 million (the "Merger"). The preferred stock (as defined below) of the Company held by the Investors (as defined below) will be contributed to Parent in exchange for new preferred shares of Parent, or sold to Parent for cash, in each case at a valuation based on the conversion or redemption value of such preferred stock. If the Merger is consummated, our shares of common stock will no longer trade on the NYSE American and will be deregistered under the Securities Exchange Act of 1934, as amended. As a result, we will become a private company. The Merger is expected to close in the second quarter of 2024, subject to various customary closing conditions, such as the approval of Battalion's stockholders. For a further discussion of the merger and redemption and conversion provisions associated with the preferred stock, refer to Item 7. *Management's Discussion and Analysis, "Recent Developments."*

- ***Preferred Stock Equity Issuances.*** On November 8, 2023, we obtained an additional support letter from Luminus Management, LLC, Oaktree Capital Management, LP, and LSP Investment Advisors, LLC, who represent our largest three existing shareholders (the "Investors") to purchase additional preferred equity securities in an amount up to $55.00 million over the next 12 months. An aggregate of 35,000 shares of preferred stock were sold on December 15, 2023 under such support letter to the Investors for proceeds of $34.1 million, net of $0.9 million of original issue discount. At December 31, 2023, $20.0 million remained available for issuance under the support letter from the Investors. The issuances of preferred stock were approved by our board of directors upon recommendation by a special committee of disinterested directors that was established to evaluate the proposed terms of the preferred stock. For a further discussion of the redemption and conversion provisions associated with the preferred stock, refer to Item 7. *Management's Discussion and Analysis, "Capital Resources and Liquidity".*

- ***H_2S Treating Joint Venture.*** In May 2022, we entered into a joint venture agreement with Caracara Services, LLC ("Caracara") to develop a strategic acid gas treatment and carbon sequestration facility (the "Facility") in Winkler County, Texas. The joint venture, operating as Wink Amine Treater, LLC ("WAT") (previously Brazos Amine Treater, LLC ("BAT")), has also entered into a Gas Treating Agreement ("GTA") with us for natural gas production from our Monument Draw area. In exchange for contributing to the joint venture a wellbore with an approved permit for the injection of acid gas and surface land , we retained a 5% equity interest in WAT, an unconsolidated subsidiary. Caracara provided the initial capital for the construction of the Facility, which is expected to have an initial capacity of approximately 30 MMcf per day, and a design capacity to treat up to 10% combined concentrations for H_2S and CO_2. During commissioning and initial operations, it was determined that additional pressure was required to initiate gas injection. To correct this issue, a positive displacement pump was ordered and installed. The Facility's injection well also experienced pressure communication between the tubing and annular space after an injection procedure. We commenced workover operations to remediate this issue and such workover operations on the well and injection tests were completed.

During the third quarter of 2023, additional complications were encountered with the workover operation causing higher than expected costs. To fund this workover operation, we advanced capital contributions totaling approximately $15.1 million during the year ended December 31, 2023 on behalf of our joint venture partner in WAT. Pursuant to the terms of the agreement governing the joint venture, we believe we have multiple remedies to recover such advance, including (1) declaring such payment a loan, which pursuant to the agreement would have an interest rate of the lesser of 15% or the maximum rate permitted by law, (2) recoupment from distributions from the joint venture and (3) reallocation of equity of the joint venture based on the relative level of total capital contributions by the parties after taking into account the advance.

We advanced additional capital contributions on behalf of our joint venture partner during the first quarter of 2024 of approximately $3.0 million to fund WAT with the necessary capital required to complete the sidetrack of the Acid Gas Injection ("AGI") well. Workover operations on the well and injection tests have now been successfully completed. WAT is now ramping up operations and our current forecast assumes the AGI facility will be processing 20,000 Mcf of natural gas per day by the second quarter of 2024.

For further details on the joint venture arrangement, see Item 7. *Management's Discussion and Analysis on Financial Condition - "Recent Developments*".

Risk Management

We have designed a risk management policy for the use of derivative instruments to provide initial protection against certain risks relating to our ongoing business operations, such as commodity price declines and price differentials between the NYMEX commodity price and the index price at the location where our production is sold. Derivative contracts are utilized to hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales of future oil and natural gas production. Our requirement, under our Amended Term Loan Agreement, is to hedge approximately 50% to 85% of our anticipated oil and natural gas production, in varying percentages by year, and on a rolling basis for the next four years. However, our decision on the price at which we choose to hedge our production is based in part on our view of current and future market conditions. Our hedge policies and objectives change as our operational profile changes but remain consistent with the requirements in effect under our Amended Term Loan Agreement. Our future performance is subject to commodity price risks and our future cash flows from operations may be volatile. We do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivatives available, we typically use fixed-price swaps, costless collars, basis swaps and WTI NYMEX roll agreements to attempt to manage price risk. The fixed-price swap agreements call for payments to, or receipts from, counterparties depending on whether the index price of oil or natural gas for the period is greater or less than the fixed price established for the period contracted under the fixed-price swap agreement. Costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the settlement price under the agreement exceeds the ceiling and payments from the counterparties if the settlement price under the agreement is below the floor. Basis swaps effectively lock in a price differential between regional prices (i.e. Midland) where the product is sold and the relevant pricing index under which the oil production is hedged (i.e. Cushing). WTI NYMEX roll agreements account for pricing adjustments to the trade month versus the delivery month for contract pricing.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. As of December 31, 2023, we did not post collateral under any of our derivative contracts as they are secured under our Amended Term Loan Agreement. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* and Item 8. *Consolidated Financial Statements and Supplementary Data*— Note 7*, "Derivative and Hedging Activities,"* for additional information.

Oil and Natural Gas Reserves

The proved reserves estimates reported herein for the years ended December 31, 2023 and 2022, have been independently evaluated by NSAI, our independent reserve engineering firm. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in their reserves reports incorporated herein each have over 20 years of industry experience. Each meet or exceed the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our board of directors has established a reserves committee composed of independent directors with experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Director of Corporate Development and Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering firm and in making a recommendation to our board of directors as to whether to approve the report prepared by our independent engineering firm. Our Vice President of Strategy and Planning is primarily responsible for overseeing the preparation of the annual reserve report by NSAI. He has approximately 14 years of oil and natural gas operations experience and has earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University, a Master of Business Administration degree from Rice University and is an active member of the Society of Petroleum Engineers.

The reserves information in this Annual Report on Form 10-K represents only estimates. Reserve evaluation is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced.

Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2023. Average prices for the 12-month period were as follows: WTI crude oil spot price of $78.21 per Bbl, adjusted by lease or field for quality, transportation fees, and market differentials and a Henry Hub natural gas spot price of $2.64 per MMBtu, adjusted by lease or field for energy content, transportation fees, and market differentials. All prices and costs associated with operating wells were held constant in accordance with SEC guidelines.

The following table presents certain proved reserve information as of December 31, 2023 (dollars in thousands):

Proved Reserves (MBoe)[(1)]	
Developed	40,129
Undeveloped	27,978
Total	68,107
PV-10[(2)]	$ 613,238
Discounted Future Income Taxes	(14,757)
Standardized measure of discounted future net cash flows	$ 598,481

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

(2) *PV-10 represents the discounted future net cash flows attributable to our proved oil and natural gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves is considered a non-U.S. GAAP financial measure as defined by the SEC. We believe that the presentation of the PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. Refer to the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.*

The following table presents estimated proved reserves at December 31, 2023:

	Proved Developed	**Proved Undeveloped**	**Total Proved**
Oil (MBbls)	18,626	15,996	34,622
Natural Gas Liquids (MBbls)	9,661	5,199	14,860
Natural Gas (MMcf)	71,051	40,698	111,749
Equivalent (MBoe)[(1)]	40,129	27,978	68,107

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

At December 31, 2023, total estimated proved reserves were approximately 68.1 MMBoe, a 23.9 MMBoe net decrease from the previous year's estimate of 92.0 MMBoe. Proved developed reserves of 40.1 MMBoe decreased approximately 6.2 MMBoe from December 31, 2022 primarily as a result of negative revisions of 3.6 MMBoe and production of 5.0 MMBoe offset by proved undeveloped ("PUD") reserve development of 2.4 MMBoe. PUD reserves of 27.9 MMBoe decreased approximately 17.7 MMBoe from December 31, 2022 as a result of the transfer of 2.4 MMBoe to proved developed producing reserves and downward revisions of 15.3 MMBoe due primarily to the removal of 13.0 MMBoe of PUDS due to decreased activity associated with managing cash flow, servicing debt and financial covenants, and ongoing work to recapitalize the business coupled with a downward revision of 2.3 MMBoe due to decreased SEC prices. All of our PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2023, approximately $33.0 million in capital expenditures went toward the development of PUD reserves, which includes drilling, completion and other facility costs associated with developing PUD wells.

Reliable technologies were used to determine areas where PUD locations are more than one offset location away from a producing well. These technologies include seismic data, wire line openhole log data, core data, log cross-sections, performance data and statistical analysis. In such areas, this data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. We relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves. Out of total PUD reserves of 27.9 MMBoe at December 31, 2023, 12.7 MMBoe were associated with 16 gross PUD locations that were more than one offset location from a producing well.

The estimates of quantities of proved reserves contained in this report were made in accordance with the definitions contained in SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting* . For additional information on our estimates of oil and natural gas reserves, the preparation of such estimates by NSAI and other information about our oil and natural gas reserves including a table detailing the changes by year of our proved reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data—"Supplemental Oil and Gas Information (Unaudited)."* We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations which is further described in Item 8. *Consolidated Financial Statements and Supplementary Data* —Note 4, *"Oil and Natural Gas Properties."*

Wells and Acreage

Our principal properties consist of leasehold interests in developed and undeveloped oil and natural gas properties and the reserves associated with these properties.

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2023 and 2022. Shut-in wells currently not capable of production are excluded from the well information below.

	Years Ended December 31,			
	2023		2022	
	Gross	Net	Gross	Net
Oil	109	86.2	111	91.2
Natural Gas	—	—	9	6.9
Total	109	86.2	120	98.1

The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,			
	2023		2022	
	Gross	Net	Gross	Net
Development Wells:				
Productive (1)	3	3.0	9	8.5
Dry	—	—	—	—
Total Development	3	3.0	9	8.5
Total Wells:				
Productive (1)	3	3.0	9	8.5
Dry	—	—	—	—
Total	3	3.0	9	8.5

(1) *Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly extension or exploratory wells where there is no production history.*

We had no exploratory or extension wells drilled for the years ended December 31, 2023 and 2022.

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying provisions. The following table presents a summary of our acreage interests as of December 31, 2023:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
State	Gross	Net	Gross	Net	Gross	Net
Texas	33,113	30,871	9,927	8,996	43,040	39,867

Generally, our oil and natural gas leases remain in force as long as production in paying quantities is maintained. Leases on our undeveloped oil and natural gas acreage are either categorized as "held by production" or perpetuated by continuous development clauses contained in our leases or tolling agreements. Of our 8,996 net undeveloped acres at December 31, 2023, approximately 5,300 acres are subject to continuous development clauses and 3,692 acres are "held by production." We continually review our acreage subject to these clauses or agreements when determining our drilling program.

Production Volumes, Sales Prices, and Average Costs

The following table summarizes our oil, natural gas and NGLs production volumes, average sales price per unit and average costs per unit:

	Years Ended December 31,	
	2023	2022
Production:		
Crude oil - MBbls	2,415	2,837
Natural gas - MMcf	8,718	9,337
Natural gas liquids - MBbls	1,163	1,242
Total MBoe *(1)*	5,031	5,635
Average daily production - Boe *(1)*	13,784	15,438
Average price per unit (excluding impact of settled derivatives)**:**		
Crude oil price - Bbl	$ 76.04	$ 94.36
Natural gas price - Mcf	1.27	4.95
Natural gas liquids price - Bbl	20.48	35.02
Barrel of oil equivalent price - Boe *(1)*	43.43	63.43
Average price per unit (including impact of settled derivatives)*(2)***:**		
Crude oil price - Bbl	$ 68.28	$ 53.54
Natural gas price - Mcf	2.36	3.40
Natural gas liquids price - Bbl	20.48	35.02
Barrel of oil equivalent price - Boe *(1)*	41.59	40.31
Average cost per Boe:		
Production:		
Lease operating	$ 8.92	$ 8.54
Workover and other	1.42	1.19
Taxes other than income	2.37	3.28
Gathering and other	12.64	11.38
Total average cost	25.35	24.39

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

(2) *Cash paid on, or cash received from, settled derivative contracts are reflected as "Net gain (loss) on derivative contracts" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting.*

Realized prices differ from the applicable spot prices due to lease or field quality, energy content, transportation fees and market differentials.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers, transporters and take-away capacity for the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

The purchasers of our oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, we have not experienced any significant losses from uncollectible accounts. In 2023, two individual purchasers of our production, Western Refining Company L.P. and Sunoco Inc., each accounted for more than 10% of total sales, collectively representing 79% of our total sales for the year. In 2022, three individual purchasers of our production, Western Refining Company L.P., Sunoco Inc. and Targa Resources Inc., each accounted for more than 10% of total sales, collectively representing 82% of our total sales for the year.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for crude oil can often be higher in the summer months during the peak travel season. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to be overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well blowouts, fires, equipment failure, human error and other events may cause accidental releases of toxic or hazardous materials, such as hydrogen sulfide, petroleum liquids, or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors*.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. On some occasions, local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency (the “EPA”), issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically govern the permitting, construction and operation of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

Beyond existing requirements, new programs and changes in existing programs may address various aspects of our business, including naturally occurring radioactive materials, oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to reclassify oil and gas wastes as hazardous wastes or to subject them to enhanced solid waste regulation. If such proposals were to be enacted, they could have a significant impact on our operating costs and on those of all the industry in general.

In the ordinary course of our operations, we do handle materials that may be subject to extensive existing RCRA regulations or that may be classified as hazardous substances under CERCLA. From time to time, releases of those materials have occurred at locations we own or at which we have operations. Under CERCLA, RCRA and analogous state laws, we have been and may be required to remove or remediate such materials.

Water Discharges

Our operations also may be subject to the federal Clean Water Act and analogous state statutes. Those laws regulate discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of spill prevention, control, and countermeasure plans in connection with on-site storage of significant quantities of oil. In the event of a discharge of oil into United States waters, we could be liable under the Oil Pollution Act for cleanup costs, damages and economic losses.

Our oil and natural gas production also generates salt water, which is disposed of by underground injection. The federal Safe Drinking Water Act (SDWA), the Underground Injection Control (UIC) regulations promulgated under the SDWA, and related state programs regulate the drilling and operation of salt water disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Our completion operations are subject to regulations that may become more stringent in either the short- or long-term. In particular, the well completion technique known as hydraulic fracturing, which is used to stimulate production of oil and natural gas, has come under increased scrutiny by the environmental community, and many local, state and federal regulators. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depths to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with substantially all of the wells for which we are the operator.

Working at the direction of Congress, the EPA issued a study in 2016 finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. The EPA also promulgated pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations to municipal sewage treatment plants. Environmental groups have encouraged the EPA to supplement those requirements. Various members of Congress likewise have from time to time introduced bills that would result in more stringent control or outright bans of the hydraulic fracturing process.

In addition, the Department of the Interior promulgated regulations concerning the use of hydraulic fracturing on lands under its jurisdiction, which includes lands on which we conduct or plan to conduct operations. While the Trump

Administration rescinded those rules, that decision is being challenged in court. Regardless of how the federal issues are eventually resolved, states have been imposing new restrictions or bans on hydraulic fracturing. Even local jurisdictions, such as Denton, Texas and several cities in Colorado, have adopted, or tried to adopt, regulations restricting hydraulic fracturing. Additional hydraulic fracturing requirements at the federal, state or local level may limit our ability to operate or increase our operating costs.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and may continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations, be subject to permits and restrictions under these statutes for emissions of air pollutants.

In 2012, 2016 and 2023, the EPA issued air regulations for the oil and natural gas industry that address emissions from certain new sources of volatile organic compounds, sulfur dioxide, air toxics, and methane. The rules included the first federal air standards for oil and natural gas wells that are hydraulically fractured, or refractured, as well as requirements for other processes and equipment, including storage tanks. Compliance has imposed, and will impose, additional requirements and costs on our operations.

In October 2015, the EPA announced that it was lowering the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion, but is reconsidering whether an even stricter standard is warranted. Implementation of the 2015 standard has been ongoing and has resulted in expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas could be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

Various studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response, governments increasingly have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and several countries, including those comprising the European Union, have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have been implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emissions targets, product bans, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration took a variety of steps to address climate change. For example, the EPA issued regulations requiring us and other companies to annually report certain greenhouse gas emissions from oil and natural gas facilities. Beyond its measuring and reporting rules, the EPA issued an “Endangerment Finding” under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step in issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities.

In addition, the Obama Administration developed a Strategy to Reduce Methane Emissions that was intended to result in a 40-45% decrease in methane emissions by 2025 from the oil and natural gas industry as compared to 2012 levels. Consistent with that strategy, the EPA issued air rules for oil and natural gas production sources, and the federal

Bureau of Land Management ("BLM") promulgated standards (later vacated) for reducing venting and flaring on public lands.

The Trump Administration tried to roll back many of the Obama-era climate change policies and rules. But shortly after his inauguration, President Biden accepted the Paris Agreement on behalf of the United States, declared climate considerations an essential part of the United States' foreign policy, limited new oil and natural gas leases on federal lands, and directed federal agencies to incorporate climate change considerations in their operations. New federal programs relating to climate change appear to be likely through at least 2024. For example, EPA announced new final regulations in December 2023 that impose more comprehensive restrictions on emissions of methane (a greenhouse gas) and volatile organic compounds from new, existing, and modified facilities in the oil and gas sector (such as wells and storage tank batteries). Among other things, the rule sets new emissions standards for certain equipment; requires routine monitoring for and repair of leaks at well sites, centralized production facilities, and compressor stations; limits flaring from existing oil wells; and prohibits flaring from new oil wells. In addition, BLM has proposed new rules to reduce venting, flaring and leaks from oil and gas production on public lands. Aside from new controls, the 2022 Inflation Reduction Act creates incentives designed to increase use of electric cars and fuels other than oil and natural gas. That statute imposes a fee on certain excess methane emissions from oil and gas facilities of $900 per metric ton of methane for 2024, $1,200 per metric ton for 2025, and $1,500 per metric ton each year thereafter.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and other natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and other natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act and the Clean Water Act. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or other natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration's hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees.

Human Capital

Employees

At Battalion, our success is delivered through our highly capable and diverse workforce. Our team is comprised of individuals with extensive technical, industry and other professional experience. By recruiting, hiring and retaining an experienced and diverse team, we are able to leverage years of experience, new ideas and problem solving in a collaborative environment. As of December 31, 2023, we had 38 full-time employees. We also engage the services of independent contractors and consultants along with certain professional service firms to support our work in specific areas. We have no collective bargaining agreements with our employees. We believe that we have good relations with our employees.

Driving and Supporting a Safety First Culture

The safety of our employees, contractors and the communities in which we operate is one of our most critical responsibilities. We believe that driving a safety first culture requires daily prioritization and includes a multi-faceted approach to provide our employees with the tools, support, education and incentives to operate safely:

- All employees, contractors and consultants performing work in the field participate in ongoing environmental, health and safety engagements including training, routine meetings, and individual coaching;
- Work stop authority – all of our employees and contractors have a responsibility to intercede and stop observed high hazard activities or conditions without proper controls;
- Policies and procedures implemented to support a safe working environment; and
- Environmental and safety metrics measuring performance linked to compensation.

Our employees and contractors are educated on the risks inherent in our operations and are equipped with tools to help them operate safely.

Compensation and Benefits

We have designed our compensation program to attract and retain talented employees with the requisite knowledge and experience. We offer market-competitive compensation programs, as well as strong health and welfare benefits along with a competitive 401(k) program. We have designed paid time off policies to allow our employees time off for family and other priorities.

Diversity and Inclusion

We believe all employees should be treated fairly and valued in our organization. Diversity of thoughts and experiences allows us to identify the best solutions within our company. All Battalion employees must act in accordance with our Employee Handbook, which is inclusive of our Code of Conduct. The Employee Handbook covers various topics including, among others, policies prohibiting harassment, discrimination and retaliation and policies covering workplace anti-violence, cybersecurity, confidential information and conduct. On an annual basis, employees are required to acknowledge and agree to abide by these policies.

Principal Office

As of December 31, 2023, we lease corporate office space in Houston, Texas at 820 Gessner Road.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports, available free of charge through our corporate website at *www.battalionoil.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our insider trading policy, regulation FD policy, corporate governance guidelines, code of conduct, code of ethics, audit committee charter, compensation committee charter, nominating and corporate governance committee charter and reserves committee charter are available on our website under the heading "Investors—Corporate Governance". Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our chief executive officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Annual Report on Form 10-K, information that you may find on our website is not part of this report.

ITEM 1A. RISK FACTORS

Risk Factors Summary

The following is a summary of the principal factors that make an investment in our common stock speculative or risky.

- Failure to complete, and delays in completing, the Merger (as defined below) which could materially and adversely affect our results of operations and our stock price.
- We will continue to incur substantial transaction-related costs in connection with the Merger.
- If the Merger does not close for any reason, it may increase the potential that we elect to "go dark".
- We and our directors and officers are, and may continue to be, subject to lawsuits relating to the Merger.
- If the merger does not close, we may be unable to either redeem or pay cash dividends on the outstanding shares of our Redeemable Preferred Stock, resulting in increases in the liquidation preference of the Redeemable Preferred Stock and the right of the holders of Redeemable Preferred Stock to receive a greater number of shares of our common stock in the event such holders elect to exercise their conversion rights. Consequently, the financial and voting interests in our Company of the holders of our common stock may be diluted.
- We are subject to various uncertainties and restrictions on the conduct of our business while the Merger is pending, which could have a material adverse effect on our business, results of operations and financial condition.
- The opinion of the financial advisor delivered to our Board prior to the signing of the Merger Agreement (as defined below) did not reflect changes in circumstances since the date of such opinion.
- Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.
- We may have difficulty financing our planned capital expenditures which could adversely affect our growth.
- Failure to comply with the covenants in our Amended Term Loan Agreement may limit our ability to borrow, result in an event of default and cause amounts outstanding under our Amended Term Loan Agreement to become immediately due and payable.
- Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.
- Historically, we have had substantial indebtedness and we may incur substantially more debt in the future. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.
- Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.
- We are subject to various contractual limitations that affect the discretion of our management in operating our business.
- Federal legislation and rulemaking could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.
- We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

- Our ability to use net operating loss carryforwards and realized built in losses to offset future taxable income for United States federal income tax purposes is subject to limitation.
- We may be required to take non-cash asset write-downs.
- Hedging transactions may limit our potential gains and increase our potential losses.
- We are substantially dependent upon our drilling success on our Delaware Basin properties.
- Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted rates of return.
- Increasing attention to environmental, social and corporate governance (“ESG”) matters may impact our business.
- We could experience periods of higher costs for various reasons, including due to higher commodity prices, increased drilling activity in the Delaware Basin and trade disputes or inflation that affect the costs of steel and other raw materials that we and our vendors rely upon, which could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget.
- We may not be able to drill wells on a substantial portion of our acreage.
- Certain of our undeveloped leasehold acreage could expire if we are unable to meet continuous development clauses or similar provisions in our leases requiring development of our undeveloped acreage and/or maintaining production on units containing the acreage.
- Our oil and natural gas activities are subject to various risks that are beyond our control.
- Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.
- Our strategy involves drilling in shale formations, using horizontal drilling and modern completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs. These uncertainties could result in an inability to meet our expectations for reserves and production.
- Title to the properties in which we have an interest may be impaired by title defects.
- We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.
- There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.
- Future sales of our common stock in the public market or the issuance of securities senior to our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and our ability to raise funds in stock offerings.
- We may choose to delist our securities from NYSE American and deregister our common stock under the Exchange Act, which could negatively affect the liquidity and trading prices of our common stock and would result in less disclosure about the Company.
- We are subject to complex federal, state, local and other laws and regulations that frequently are amended to impose more stringent requirements that could adversely affect the cost, manner or feasibility of doing business.
- Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.
- Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.
- Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner.
- Events beyond our control, including a global or domestic health crisis, may result in unexpected adverse operating and financial results.
- A financial downturn could negatively affect our business, results of operations, financial condition and liquidity.
- We depend on computer, telecommunications and information technology systems to conduct our business, and failures, disruptions, cyber-attacks or other breaches in data security could significantly disrupt our business operations, create liability and increase our costs.

Risks Related to the Proposed Merger

Failure to complete, and delays in completing, the Merger with could materially and adversely affect our results of operations and our stock price.

On December 14, 2023, we entered into the Merger Agreement with Fury Resources, Inc. ("Parent") and San Jacinto Merger Sub, Inc ("Merger Sub"), a direct wholly-owned subsidiary of Parent, pursuant to which Parent will acquire all of the outstanding shares of common stock of the Company. The consummation of the Merger is subject to a number of conditions, including certain financing conditions, that must be satisfied by Parent and Merger Sub, as well as other conditions, a number of which are not within our control. Failure to satisfy the conditions to the Merger could prevent, delay or otherwise materially and adversely affect the completion of the Merger. We can provide no assurance that all closing conditions will be satisfied or as to the terms, conditions and timing or of the completion of the Merger. We also cannot assure you that we will be able to successfully consummate the Merger as currently contemplated under the Merger Agreement or at all. Risks related to the failure of the Merger to be consummated include, but are not limited to, the following:

- under some circumstances, we may be required to pay a termination fee of $3.5 million;
- we will remain liable for significant transaction costs, including legal, accounting, financial advisory, and other costs relating to the Merger regardless of whether the Merger is consummated;
- we may experience negative reactions from financial markets or the trading price of our common stock may decline to the extent that the current market price for our common stock reflects a market assumption that the Merger will be completed;
- the attention of our management and employees may have been diverted by the Merger;
- we and our directors and officers could be subject to litigation relating to the Merger, including relating to any failure to complete the Merger;
- the potential loss of key personnel during the pendency of the Merger as employees may experience uncertainty about their future roles with us following completion of the Merger;
- the potential loss of, and negative reactions from business partners or those with whom we are seeking to establish business relationships, due to uncertainties about the Merger, and;
- under the Merger Agreement, we are subject to certain restrictions prior to completing the Merger, which restrictions could adversely affect our ability to conduct our business as we otherwise would have done if we were not subject to these restrictions.

The occurrence of any of these events individually or in combination could materially and adversely affect our business, results of operations, financial condition, and stock price. If the Merger is not consummated and one or more of these events occur, such as payment of a termination fee or other significant transaction costs in connection with the Merger, our cash balances and other outstanding indebtedness at that time could be materially and adversely impacted and our options for sources of financing or refinancing could be more limited than if we had not pursued the Merger. If the Merger is not completed, there can be no assurance that these risks will not materialize and will not materially and adversely affect our stock price, business, financial condition, results of operations or cash flows.

We will continue to incur substantial transaction-related costs in connection with the Merger.

We have incurred significant legal, advisory and financial services fees in connection with Merger. We have incurred, and expect to continue to incur, additional costs in connection with the satisfaction of the various conditions to closing of the Merger, including seeking approval from our stockholders and from applicable regulatory authorities. Any delays in the consummation of the Merger could increase these costs significantly.

If the Merger does not close for any reason, it may increase the potential that we elect to "go dark".

As noted elsewhere herein, we have recently considered the advisability of taking steps to delist our securities with the NYSE American and discontinue our obligations to make periodic filings with the SEC by deregistering our securities with the SEC (i.e., “going dark”) so as to reduce ongoing costs and expenses, while simultaneously pursuing strategic transactions that might render such action unnecessary. We have incurred substantial additional expenses in connection with the Merger and may find it advisable to follow through on a plan to go dark should the Merger Agreement be terminated or the Merger not close for any reason.

We and our directors and officers are, and may continue to be, subject to lawsuits relating to the Merger.

Litigation is very common in connection with the sale of public companies, regardless of whether the claims have any merit. One of the conditions to consummating the Merger is that no order enjoining, prohibiting or otherwise making illegal the consummation of the Merger shall have been issued by any governmental authority, including a court. These or any similar securities class action lawsuits and derivative lawsuits, regardless of their merits, may result in substantial costs and divert management time and resources. An adverse judgment in such cases could have a negative impact on our liquidity and financial condition or could prevent the Merger from being completed.

If the Merger does not close, we may be unable to either redeem or pay cash dividends on the outstanding shares of our Redeemable Preferred Stock, resulting in increases in the liquidation preference of the Redeemable Preferred Stock and the right of the holders of the Redeemable Preferred Stock to receive a greater number of shares of our common stock in the event such holders elect to exercise their conversion rights. Consequently, the financial and voting interests in our Company of the holders of our common stock may be diluted.

As noted elsewhere herein, the Company has issued shares of Redeemable Preferred Stock with an initial aggregate liquidation value of $98.0 million. Dividends are payable on the Redeemable Preferred Stock at a rate of 14.5% per annum; however, in the event the Company does not declare and pay dividends in cash when due, the dividend rate increases to 16.0% per annum and is added to the liquidation value of the Redeemable Preferred Stock. The Company has heretofore not paid dividends on the Redeemable Preferred Stock in cash and is not expected to in the future. Accordingly, the liquidation value of the Redeemable Preferred Stock is increasing and would be expected to increase in the future. In addition to other rights, the holders of the Redeemable Preferred Stock are also entitled generally to convert their shares of Redeemable Preferred Stock into shares of our common stock by dividing a “conversion price” specified in the terms of the Redeemable Preferred Stock into the then current liquidation preference of the Redeemable Preferred Stock, such that increases in the liquidation preference may ordinarily result in an increase in the number of shares of common stock received by such holder upon conversion. Accordingly, if the Merger does not close and the Company is unable to redeem the Redeemable Preferred Stock or is unable to pay, or elects not to pay, dividends on the Redeemable Preferred Stock in cash, the liquidation preference of the Redeemable Preferred Stock will continue to increase, thereby diluting the financial interests of the holders of our common stock in our Company and diluting the voting interests of the holders of our common stock to the extent holders of the Redeemable Preferred Stock elect to convert such shares into shares of our common stock.

We are subject to various uncertainties and restrictions on the conduct of our business while the Merger is pending, which could have a material adverse effect on our business, results of operations and financial condition.

Uncertainty about the pendency of the Merger and the effect of the Merger on our employees, customers, suppliers and other third parties who deal with us may have a material adverse effect on our business, results of operations and financial condition. These uncertainties may impair our ability to attract, retain and motivate key personnel pending the consummation of the Merger, as such personnel may experience uncertainty about their future roles following the consummation of the Merger. Additionally, these uncertainties could cause other business partners who deal with us to seek to change existing business relationships with us or fail to extend an existing relationship with us, which could have a material adverse effect on our business, results of operations, financial condition and market price of our common stock.

The opinion of the financial advisor delivered to our Board prior to the signing of the Merger Agreement did not reflect changes in circumstances since the date of such opinion.

The opinion of Houlihan Lokey, the financial advisor to the Company in connection with the Merger, was delivered to the our Board on December 14, 2023, and was dated December 14, 2023. Changes in our operations and prospects, general market and economic conditions and other factors that were beyond our control may have significantly altered the Company's value or the price of shares of our common stock by the time the Merger is completed. The opinion does not speak as of the time the Merger will be completed or as of any date other than the date of such opinion.

Financial and Liquidity Risk Factors

Oil, NGL and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability, future growth and the carrying value of our properties depend substantially on prevailing oil, NGL and natural gas prices. Prices also affect the amount of cash flow we have available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Oil, NGL and natural gas prices are volatile. Among the factors that affect volatility are:

- domestic and foreign supplies of oil, NGLs and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other oil exporting countries, including Russia, to agree upon and maintain production quotas;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as the Middle East, and armed conflict or terrorist attacks;
- the level of consumer demand for oil and natural gas, including demand growth in developing countries, such as China and India;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand for oil and natural gas;
- the price and availability of alternative fuels and energy sources;
- the price and availability of foreign imports and domestic exports; and
- worldwide and regional economic and political conditions impacting the global supply and demand for oil and natural gas, which may be driven by many factors, including sanctions, import and export restrictions, climate change initiatives and environmental protection affects, health epidemics (such as the global COVID-19 coronavirus outbreak) and numerous other factors.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

Our business requires substantial capital expenditures primarily to fund our drilling program. We may also continue to selectively increase our acreage position, which would require capital in addition to the capital necessary to drill on our existing acreage. It is possible that we will acquire acreage in other areas that we believe are prospective for oil and natural gas production and expend capital to develop such acreage. We expect to use proceeds from the sales of redeemable convertible preferred stock, if necessary, and which may be difficult or limited to access, to fund capital expenditures that are in excess of our operating cash flow and cash on hand.

Additionally, certain segments of the investor community have negative sentiment towards investing in our industry, with some investors and investment advisors adopting policies negatively impacting investment in the oil and gas sector based on social and environmental considerations. Commercial and investment banks have also come under pressure to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could potentially result in a reduction of available capital funding for development projects, thus impacting future financial results.

If we are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisitions and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and the sale of some of our assets on an unfavorable basis, each of which could have a material adverse effect on our results and future operations.

Failure to comply with the covenants in our Amended Term Loan Agreement may limit our ability to borrow, result in an event of default and cause amounts outstanding under our Amended Term Loan Agreement to become immediately due and payable.

On November 24, 2021, the Company and its wholly owned subsidiary, Halcón Holdings, LLC (Borrower) entered into an Amended and Restated Senior Secured Credit Agreement (Term Loan Agreement) with Macquarie Bank Limited, as administrative agent, and certain other financial institutions party thereto, as lenders. On November 14, 2022, the Company entered into a further Amended Credit Agreement (the "Amended Term Loan Agreement") with its lenders which modified certain provisions of its original Term Loan Agreement. Our Amended Term Loan Agreement limits our borrowings.

As of December 31, 2023, we had approximately $200.0 million of indebtedness outstanding and approximately $0.3 million of letters of credit outstanding under the Amended Term Loan Agreement. As of December 31, 2023, we have no additional borrowing capacity under the Amended Term Loan. Additionally, our Amended Term Loan Agreement contains certain covenants (namely our Current Ratio covenant) as well as a mandatory repayment schedule requiring us to make scheduled amortization payments in the aggregate amount of $50.0 million in 2024 and $35.0 million in the aggregate from the fiscal quarter ending March 31, 2025 through the fiscal quarter ending September 30, 2025.

In November 2022, anticipated non-compliance with our Current Ratio covenant required us to amend our Term Loan Agreement which reduced our Current Ratio requirement through March 31, 2023. Additionally, in order to provide sufficient liquidity in 2023 to address upcoming debt maturities and covenant compliance while funding our operating and capital programs, we obtained approximately $95.6 million of additional equity funding from certain of our existing equity shareholders during 2023. For a further discussion of these actions, refer to Item 7*, Management's Discussion and Analysis, "Capital Resources and Liquidity"* and Item 9B. *Other Information.*

Our Amended Term Loan Agreement contains the following financial covenants (as defined), including the maintenance of the following ratios:

- Asset Coverage Ratio of not less than 1.80 to 1.00 as of December 31, 2023 and the last day of each fiscal quarter thereafter;
- Total Net Leverage Ratio of not greater than 2.50 to 1.00 as of December 31, 2023 and each fiscal quarter thereafter, and
- Current Ratio of not less than 1.00 to 1.00, determined as of the last day of any fiscal quarter period, as of December 31, 2023 and for each fiscal quarter thereafter.

As of December 31, 2023, the Company was in compliance with its financial covenants under the Amended Term Loan Agreement.

As described above and in other historical periods, we have periodically sought amendments to the covenants under our revolving credit agreements, including the financial covenants, where we have anticipated difficulty in maintaining compliance. In the event we have difficulty in the future meeting the covenants under our Amended Term Loan Agreement, we would be required to seek additional relief, and there is no assurance that it would be granted. Failure to comply with the covenants in our Amended Term Loan Agreement may limit our ability to borrow, result in an event of default and cause amounts outstanding under our Amended Term Loan Agreement to become immediately due and payable.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Our future oil and natural gas reserves and production and, therefore, our cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition, results of operations and cash flows.

We have substantial indebtedness and we may incur substantially more debt in the future. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have approximately $200.0 million principal amount of debt, including current portions, as of December 31, 2023. As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, and outstanding principal during 2024, which will reduce the amount of cash flow we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes or adverse developments in our business or economic downturns impacting the industry in which we operate. Indebtedness under our Amended Term Loan Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have hedging arrangements that are effective in offsetting interest rate fluctuations. A rise in interest rates could impact on our borrowing costs and could have an adverse effect on our cash flows. In conjunction with the amendment of our Term Loan Agreement in November 2022, we (i) converted our benchmark interest rate from a London Interbank Offered Rate (“LIBOR”) to a Secured Overnight Financing Rate (“SOFR”) plus 0.15% and (ii) increased the applicable margin on borrowings by 0.50%. Borrowings under the Amended Term Loan Agreement will now bear interest at a rate per annum equal to the SOFR plus 7.65%.

We may incur substantially more debt in the future. Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional shares of common or preferred stock on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves. The process of estimating oil and natural gas reserves in accordance with SEC requirements is complex, involving significant estimates and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The estimates of our reserves as of December 31, 2023 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, in accordance with SEC requirements, estimates of oil and gas reserves, future net revenue from proved reserves and the present value of our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the 12-month first-day-of-the-month average oil and gas prices for the year ended December 31, 2023. Average prices for oil and natural gas for the 12-month period were as follows: WTI crude oil spot price of $78.21 per Bbl, adjusted by lease or field for quality, transportation fees, and market differentials and a Henry Hub natural gas spot price of $2.64 per MMBtu, adjusted by lease or field for energy content, transportation fees, and market differentials. Any significant variance in the actual future prices from these assumptions could materially affect the estimated quantity and value of our reserves set forth in this report.

In addition, at December 31, 2023, approximately 41% of our estimated proved reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Estimated proved reserves as of December 31, 2023 assume that we will make future capital expenditures of approximately $387.2 million in the aggregate primarily from 2024 through 2027, which are necessary to develop and realize the value of proved reserves on our properties. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations; however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We are subject to various contractual limitations that affect the discretion of our management in operating our business.

Our Amended Term Loan Agreement contains various provisions that may limit our management's discretion in certain respects. In particular, the Amended Term Loan Agreement limits our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase shares of our common stock and any other capital stock we may issue;
- make loans to others;
- make investments;
- incur additional indebtedness;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- increase our exposure to commodity price fluctuations;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

Compliance with these and other limitations may limit our ability to operate and finance our business and engage in certain transactions in the manner we might otherwise. In addition, if we fail to comply with the limitations under our Amended Term Loan Agreement, our creditors, to the extent the agreement so provides, may accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us.

Federal legislation and rulemaking could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. The Dodd-Frank Act may require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The counterparties to our derivative instruments may also spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing commodity derivative contracts. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a material effect on our financial position, results of operations and cash flows.

Our ability to use net operating loss carryforwards and realized built in losses to offset future taxable income for U.S. federal income tax purposes is subject to limitation.

In general, under Section 382 of the Internal Revenue Code of 1986, as amended, a corporation that undergoes an “ownership change” is subject to limitations on its ability to utilize its pre-change net operating losses (NOLs), and realized built in losses (RBILS), to offset future taxable income. In general, an ownership change occurs if the aggregate stock ownership of certain stockholders (generally 5% stockholders, applying certain look-through rules) increases by more than 50 percentage points over such stockholders’ lowest percentage ownership during the testing period (generally three years).

We experienced ownership changes in December 2018 and October 2019 and we may experience additional ownership changes in the future. Limitations imposed on our ability to use NOLs and RBILS to offset future taxable income may cause U.S. federal income taxes to be paid earlier than otherwise would be paid if such limitations were not in effect and could cause such NOLs and RBILS to expire unused, in each case reducing or eliminating the benefit of such NOLs and RBILS. Similar rules and limitations may apply for state income tax purposes. As of December 31, 2023, no additional ownership change has occurred.

We may be required to take non-cash asset write-downs.

We may be required under full cost accounting rules to write-down the carrying value of oil and natural gas properties if oil and natural gas prices decline or if there are substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We utilize the full cost method of accounting for oil and natural gas exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or “ceiling,” of the book value of oil and natural gas properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted arithmetic average of the first day of each month for the 12-month period ending at the balance sheet date. If the net book value of oil and natural gas properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, SEC regulations require us to impair or "write-down" the book value of our oil and natural gas properties.

Costs associated with unevaluated properties, which were approximately $58.9 million at December 31, 2023, are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to depletion and the ceiling test limitation.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production and comply with the requirements of our Amended Term Loan Agreement, we have entered into oil and natural gas hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile commodity prices, such transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or
- the counterparties to our hedging agreements fail to perform under the contracts.

Operational Risk Factors

We are substantially dependent upon our drilling success on our Delaware Basin properties.

We are a pure-play, single-basin operator in the Delaware Basin in West Texas. As a consequence of this geographical concentration, we may have greater exposure to the impact of regional supply and demand factors, delays or interruptions in production from governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, or other conditions adversely impacting our ability to produce or market our production. Such events could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted rates of return.

Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon current and future market prices for our oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. The costs of drilling and completing a well are often uncertain, and are affected by many factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions; and
- compliance with governmental requirements.

If we are unable to accurately predict and control the costs of drilling and completing a well, we may be forced to limit, delay or cancel drilling operations.

Increasing attention to ESG matters may impact our business.

Companies conducting oil and natural gas activities, like many firms in other industries, are facing increased scrutiny from stakeholders related to their ESG policies and practices. Stakeholder expectations and standards around ESG are evolving and companies that do not adapt or comply with those expectations and standards, regardless of whether there is a legal requirement to do so, may be adversely impacted. Increased attention to ESG matters may impact our business by increasing costs, reducing demand for oil and natural gas, reducing profits, increasing regulations and litigation, or impeding our access to capital and may negatively impact our stock price.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their ESG approaches. Currently, there are no universal standards for scores or ratings; however, the importance of sustainability evaluations is becoming more broadly accepted and utilized by investors and stockholders. Unfavorable ratings or assessment of our ESG practices may lead to negative investor sentiment toward us, which could have a negative impact on our stock price and our access to capital.

We could experience periods of higher costs for various reasons, including due to higher commodity prices, increased drilling activity in the Delaware Basin and trade disputes or inflation that affect the costs of steel and other raw materials that we and our vendors rely upon, which could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget.

Our industry is cyclical. When oil, natural gas and natural gas liquids prices increase, shortages of drilling rigs, equipment, supplies, water or qualified personnel may result. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production, particularly in the Delaware Basin, likewise may increase demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. Cost increases may also result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other materials that we and our vendors rely upon and increases in the cost of services to process, treat and transport our production. Any escalation or expansion of tariffs could result in higher costs and affect a greater range of materials we rely upon in our business. The unavailability or high cost of drilling rigs, pressure pumping equipment, tubulars and other supplies, and of qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment and related services, we may enter into contracts that extend over several months or years. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate enough cash flow from operations or be able to raise sufficient capital to do so. Commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we conduct may not be successful or result in additional proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Certain of our undeveloped leasehold acreage could expire if we are unable to meet continuous development clauses or similar provisions in our leases requiring development of our undeveloped acreage and/or maintaining production on units containing the acreage.

As of December 31, 2023, we owned leasehold interests in approximately 40,000 net acres in the Delaware Basin in West Texas of which approximately 9,000 net acres are undeveloped. Generally, our oil and natural gas leases remain in force as long as production in paying quantities is maintained. Currently, our leases on undeveloped oil and natural gas properties are either categorized as “held by production” or perpetuated by continuous development clauses contained in our leases or tolling agreements. We continually review our leases on acreage subject to these clauses or agreements when planning for our future drilling programs. If our leases on acreage subject to these provisions are not maintained by production in paying quantities or continuous development, our leases could expire and we would lose our right to develop the related properties.

Our drilling plans are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, while not material, some of our acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and are therefore subject to additional risk of expirations.

Our oil and natural gas activities are subject to various risks that are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in, the prospects in which we have or will acquire an interest. Such risks and hazards include:

- human error, accidents and other events beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, adverse weather events, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- accidental releases of natural gas, including gas with high levels of hydrogen sulfide (H2S), and other hydrocarbons or toxic or hazardous materials in the environment as a result of human error or the malfunction of equipment or facilities, which can result in personal injury and loss of life, pollution, damage to equipment and suspension of operations;
- well-on-well interference that may reduce recoveries;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

Some of these risks may be exacerbated by other risks that we face. For instance, certain of our wells produce high levels of H2S, a highly toxic, naturally-occurring gas frequently associated with oil and natural gas production. Safely handling H2S gas requires highly skilled operations and field personnel as well as specialized infrastructure, treating facilities, disposal facilities, and/or third party sour gas takeaway. If we are unable to attract and retain qualified and highly skilled personnel our ability to effectively manage this and other risks may be adversely impacted. Additionally, if we are unable to successfully operate our specialized treating facilities or secure adequate sour gas takeaway capacity from third parties when and if necessary, our ability to effectively manage the H2S levels we see in our natural gas production may be adversely impacted. As a result, our production, revenues, operating costs and liabilities and expenses may be materially and adversely affected and may differ materially from those anticipated by us and availability of certain facilities may impact our processing costs.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it may be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks or trains to transport our production, which is more expensive and less efficient than transportation via pipeline. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions, the availability and cost of capital, public opposition, regulatory restrictions and judicial challenges. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut-in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently expect, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut-in, from time to time for numerous other reasons, including as a result of weather conditions (which may worsen due to climate changes), accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Our strategy involves drilling in shale formations, using horizontal drilling and modern completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs. These uncertainties could result in an inability to meet our expectations for reserves and production.

The drilling of long horizontal laterals and the use of modern completion techniques with multi-stage fracture stimulation in shale formations involves certain risks and complexities that do not exist in conventional wells. Such risks include, but are not limited to, landing the horizontal wellbore in the desired drilling zone, maintaining the desired drilling zone while drilling horizontally through the wellbore formation, running casing through the full span of the wellbore, and being able to run tools and other necessary equipment consistently throughout the horizontal wellbore. Additionally, horizontal drilling and completion techniques may result in faster production decline rates relative to conventional drilling methods. The ultimate success of our drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated, our investment in these areas may not be as attractive as we anticipate and could result in material write-downs of unevaluated properties and future declines in the value of our undeveloped acreage.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Investment in Securities Risk Factors

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

Funds advised by Luminus Management, LLC, Oaktree Capital Management, LP, and LSP Investment Advisors, LLC held approximately 37.4%, 24.2% and 14.4%, respectively, of our common stock as of March 25, 2024. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures, or the issuance of additional equity securities or debt, that, in their judgment, could enhance their investment in us or another company in which they invest. Such transactions might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our common shares because investors may perceive disadvantages in owning shares in companies with significant stockholders.

Future sales of our common stock in the public market or the issuance of securities senior to our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and our ability to raise funds in stock offerings.

A large percentage of our shares of common stock are held by a relatively small number of investors. Sales by us or our stockholders of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur, could cause the market price of our common stock to decline or could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

We are currently authorized to issue 100.0 million shares of common stock and 1.0 million shares of preferred stock, with such designations, rights, preferences, privileges and restrictions as determined by the Board. As of March 25, 2024, we had approximately 16.5 million shares of common stock outstanding and options and restricted stock units to purchase or receive an aggregate of 0.4 million shares of our common stock. As of March 25, 2024, we have also reserved an additional $1.1 million shares for future issuance to our directors, officers and employees under our 2020 Long-Term Incentive Plan. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock.

We may issue common stock or other equity securities senior to our common stock in the future for a number of reasons, including to finance acquisitions, to adjust our leverage ratio, and to satisfy our obligations upon the exercise of warrants and options, or for other reasons. We cannot predict the effect, if any, that future sales or issuances of shares of our common stock or other equity securities, or the availability of shares of common stock or such other equity securities for future sale or issuance, will have on the trading price of our common stock.

We may choose to delist our securities from NYSE American and deregister our common stock under the Exchange Act, which could negatively affect the liquidity and trading prices of our common stock and would result in less disclosure about the Company.

As further discussed in Item 7. *Management's Discussion and Analysis, "Capital Resources and Liquidity,"* we are exploring strategic transactions and looking at opportunities to significantly reduce expenses in the near term to bolster liquidity. Given the cost and resource demands of being a public company, we may decide to "go dark," or discontinue our obligation to make periodic filings with the SEC, by delisting our securities with NYSE American and deregistering our securities with the SEC. While no decision has been made, should we ultimately make the decision to go dark, there would be a substantial decrease in disclosure by us of our operations and prospects, and a potential decrease in the liquidity in our common stock even though stockholders may still continue to trade our common stock on an over-the-counter (OTC) market. As a result of going dark, investors may find it more difficult to dispose of or obtain accurate quotations as to the market value of our common stock, and the ability of our stockholders to sell our common stock in the secondary market may be materially limited.

Regulatory Risk Factors

We are subject to complex federal, state, local and other laws and regulations that frequently are amended to impose more stringent requirements that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for, develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our activities, we may not be able to conduct our operations as planned. We also may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, air emissions, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with applicable laws may result in the suspension or termination of operations and subject us to liabilities, including administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, the laws governing our operations or the enforcement thereof could change in ways that substantially increase our costs of doing business. For example, negative public perception regarding us and/or our industry may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations.

Under environmental, health and safety laws and regulations, we also could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Such laws may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling and pipeline projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation relating to conservation practices and protection of correlative rights. Such regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. By way of example, in 2015 the EPA lowered the primary national ambient air quality standard for ozone from 75 parts per billion to 70 parts per billion and is reconsidering whether an even stricter standard is warranted. Implementation eventually could result in more stringent emissions controls and additional permitting obligations for our operations.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we currently conduct operations, or may in the future, plan to conduct operations. Consequently, we could be subject to additional levels of regulation, operational delays or increased operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to require more stringent federal control or outright bans of hydraulic fracturing. Further, the EPA issued a study in 2016 finding that hydraulic fracturing could potentially harm drinking water resources under adverse circumstances such as injection directly into groundwater or into production wells lacking mechanical integrity. Other governmental reviews have also been conducted that focus on environmental aspects of hydraulic fracturing. Such activities eventually could result in additional regulatory control.

Certain states, including Texas where we conduct our operations, likewise are considering or have adopted more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing.

The proliferation of regulations may limit our ability to operate. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Various studies have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response, governments increasingly have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, the Kyoto Protocol and the Paris Agreement address greenhouse gas emissions, and international negotiations over climate change and greenhouse gases are continuing. Meanwhile, several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

In the United States, many states, either individually or through multi-state regional initiatives, have been implementing legal measures to reduce emissions of greenhouse gases, primarily through emission inventories, emission targets, product bans, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration addressed climate change through a variety of administrative actions. The EPA thus issued greenhouse gas monitoring and reporting regulations that cover oil and natural gas facilities, among other industries. Beyond measuring and reporting, the EPA issued an “Endangerment Finding” under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, then President Obama released a Strategy to Reduce Methane Emissions that included consideration of both voluntary programs and targeted regulations for the oil and gas sector. Consistent with that strategy, the EPA issued final rules in 2016 for new and modified oil and gas production sources (including hydraulically fractured oil wells, natural gas well sites, natural gas processing plants, natural gas gathering and boosting stations and natural gas transmission sources) to reduce emissions of methane as well as volatile organic compound and toxic pollutants. In addition, the BLM promulgated standards for reducing venting and flaring on public lands (which were eventually vacated).

The Trump Administration tried to roll back many of the Obama-era climate change policies and rules. But shortly after his inauguration, President Biden accepted the Paris Agreement on behalf of the United States, declared climate considerations an essential part of the United States’ foreign policy, limited new oil and natural gas leases on federal lands, and directed federal agencies to incorporate climate change considerations in their operations. New federal programs relating to climate change appear to be likely through at least 2024. For example, the EPA announced new final regulations in December 2023 that impose more comprehensive restrictions on emissions of methane (a greenhouse gas) and volatile organic compounds from new, existing, and modified facilities in the oil and gas sector (such as wells and storage tank batteries). Among other things, the rule sets new emissions standards for certain equipment; requires routine monitoring for and repair of leaks at well sites, centralized production facilities, and compressor stations; limits flaring from existing oil wells; and prohibits flaring from new oil wells. In addition, BLM has proposed new rules to reduce venting, flaring and leaks from oil and gas production on public lands. Aside from new controls, the 2022 Inflation Reduction Act creates incentives designed to increase use of electric cars and fuels other than oil and natural gas. That statute imposes a fee on certain excess methane emissions from oil and gas facilities of $900 per metric ton of methane for 2024, $1,200 per metric ton for 2025, and $1,500 per metric ton each year thereafter.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that cause or contribute to significant greenhouse gas emissions. Such cases may seek emissions reductions, challenge air emissions or other permits or request damages for alleged climate change impacts to the environment, people, and property.

Any new initiatives that may be adopted to reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our products.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas liquids and natural gas, which could have an adverse effect on our business, financial condition and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which is leading to greater public scrutiny and regulation of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

Macroeconomic Risk Factors

Our business could be adversely impacted by events beyond our control, including economic downturns, inflation, increases in interest rates, natural disasters, public health crises such as pandemics, political crises, geopolitical events such as the conflict in Ukraine and the Middle East, or other macroeconomic conditions, which have in the past and may in the future result in adverse operating and financial results.

The global economy, including credit and financial markets, has experienced extreme volatility and disruptions, including, among other things, severely diminished liquidity and credit availability, declines in consumer confidence, declines in economic growth, supply chain shortages, increases in inflation rates, higher interest rates and uncertainty about economic stability.

A widespread public health crisis such as a pandemic could result in significant disruption of global financial markets, reducing our ability to access capital, which could negatively affect our liquidity. In addition, a recession or market correction resulting from the effects of public health crises could materially affect our business and the value of our common stock. It may have further negative impacts, such as (a) a global or U.S. recession or other economic crisis; (b) credit and capital markets volatility (and access to these markets, including by our suppliers and customers); (c) manufacturing supply disruption due to travel restrictions or other government actions; and (d) disruptions services and supplies. The ultimate impact of a public health crisis is highly uncertain.

The Federal Reserve recently raised interest rates multiple times in response to concerns about inflation and it may raise them again. Higher interest rates, coupled with reduced government spending and volatility in financial markets may increase economic uncertainty and affect consumer spending. If the equity and credit markets deteriorate, including as a result of political unrest or war, it may make any necessary debt or equity financing more difficult to obtain in a timely manner or on favorable terms, more costly or more dilutive. Increased inflation rates can adversely affect us by increasing our costs, including labor and employee benefit costs.

A financial downturn could negatively affect our business, results of operations, financial condition and liquidity.

Actual or anticipated declines in domestic or foreign economic growth rates, regional or worldwide increases in tariffs or other trade restrictions, turmoil affecting the U.S. or global financial system and markets and a severe economic contraction either regionally or worldwide, resulting from efforts to contain the COVID-19 coronavirus or other factors, could materially affect our business and financial condition and impact our ability to finance operations by worsening the actual or anticipated future drop in worldwide oil demand, negatively impacting the price we receive for our oil and natural gas production. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our vendors and suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations. All of the foregoing may adversely affect our business, financial condition, results of operations and cash flows.

Cybersecurity Risk Factors

We depend on computer, telecommunications and information technology systems to conduct our business, and failures, disruptions, cyber-attacks or other breaches in data security could significantly disrupt our business operations, create liability and increase our costs.

The oil and natural gas industry in general has become increasingly dependent upon technology to conduct day-to-day operations, including certain exploration, development and production activities. We have agreements with third parties for hardware, software, telecommunications and other information technology services necessary to our business and have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We use these systems and data to, among other things, estimate quantities of oil, natural gas liquids and natural gas reserves, process and record financial data and communicate with our employees and third parties. Failures in these systems due to hardware or software malfunctions, computer viruses, natural disasters, fire, human error or other causes could significantly affect our ability to conduct our business. In particular, cyber-security attacks on systems are increasing in frequency and sophistication and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to them, there can be no assurance that these procedures and controls will be sufficient to prevent security threats from materializing and any interruptions to our arrangements with third parties, to our computing and communications infrastructure or our information systems could significantly disrupt our business operations. Further, the loss or corruption of sensitive information could have a material adverse effect on our reputation, financial position, results of operations or cash flows. In addition, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks. We generally do not maintain insurance coverage for the costs associated with cyber-security events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Risk Management and Strategy

We rely on information technology to operate our business. We have endpoint and other protection systems, and incident response processes, both internally and through third-party experts designed to protect our information technology systems. These established processes assist us to continuously assess and identify threats to our systems and minimize impact to our business in the event of a breach or other security incident. With our third-party consultants, the processes protect our information systems and allow us to resolve any issue which may arise in the most timely and aggressive fashion. Our internal auditors perform audit engagements to assess our strategies, policies, procedures, and controls to reduce the risk of a cybersecurity incident.

As any new threat to security may be identified, our personnel are notified, with instruction to increase awareness of the threat and how to react if such a threat or actual breach appears to be encountered. Periodic educational notices are also disseminated to all personnel. Additionally, as our systems are modified and upgraded, all personnel are notified, with instruction as appropriate. With the assistance and advice of our expert consultants, responsibility for the identification and assessment of risks and the recommendation of upgrades to our systems resides with our Director of Information Technology, who reports to our Chief Executive Officer.

Governance

Our Board oversees the risks involved in our operations as part of its general oversight function, integrating risk management into our compliance policies and procedures. With respect to cybersecurity, the Board has the ultimate oversight responsibility, with the Audit Committee of the Board having certain responsibilities relating to risk management of cybersecurity.

Among other things, the Audit Committee discusses with management the Company’s major policies with respect to risk assessment and risk management, including cybersecurity, as they relate to the integrity of the Company’s accounting and financial reporting processes and the Company’s compliance with legal and regulatory requirement.

In addition, the Audit Committee, with the assistance and advice of Company management and third-party consultants, oversees operational information technology risks, including cybersecurity, as they relate to the technical aspects of the Company’s operations. The Audit Committee receives quarterly reports from Company management, which includes cybersecurity risk factors.

The Board routinely receives information and updates from Company management and the Audit Committee with respect to the effectiveness of the Company's information systems' security framework, which may include cybersecurity assessments, risk management, and mitigation measures. The Board will also be provided updates on any material incidents relating to information systems security and cybersecurity incidents. As discussed above, we maintain endpoint and other protection systems, and incident response processes, both internally and through third-party experts.

We have not identified an indication of a substantive cybersecurity incident that would have a material impact on our business, results of operations or financial statements. For additional information regarding risks from cybersecurity threats, please refer to Item 1A *Risk Factors* above.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. *Business* and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 9*, "Commitments and Contingencies,"* and is incorporated herein by reference.

Under rules promulgated by the SEC, administrative or judicial proceedings arising under any federal, state or local provisions that have been enacted or adopted regulating the discharge of materials into the environment or primarily for the purpose of protecting the environment are disclosed if the governmental authority is party to such proceeding and the proceeding involves potential monetary sanctions of $300,000 or more. We are not party to any such proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

On February 20, 2020, our common stock commenced trading on the NYSE American exchange under the symbol "BATL." Approximately 50 registered stockholders of record as of March 18, 2024 held our common stock. In most instances, a registered stockholder holds shares in street name for one or more customers who beneficially own the shares.

We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our Amended Term Loan Agreement.

During 2023, we sold, in private placements, an aggregate of 98,000 shares of redeemable convertible preferred stock, par value $0.0001 per share, for total net proceeds of $95.6 million to certain funds managed by Luminus Management, LLC, Oaktree Capital Management, LP, and LSP Investment Advisors, LLC, the Company's largest three existing stockholders (collectively, the "Investors") that represent 50 percent of our board of directors. Proceeds from such sales were used to fund operations and meet debt payment requirements. The private placements of the redeemable convertible preferred stock were undertaken in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof. For additional information and a description of conversion, see Part I. Item 8. Consolidated Financial Statements and Supplementary Data – Footnote 11 “Redeemable Convertible Preferred Stock” to this Annual Report on Form 10-K.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

None.

ITEM 6. RESERVED

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward- looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed. For more information, see “*Special note regarding forward-looking statements* .”

Overview

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. During 2017, we acquired certain properties in the Delaware Basin and divested our assets located in the Williston Basin in North Dakota and in the El Halcón area of East Texas. As a result, our properties and drilling activities are currently focused in the Delaware Basin, where we have an extensive drilling inventory that we believe offers attractive economics.

Our financial results depend upon many factors but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, transportation take-away capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

When commodity prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. While we use derivative instruments to provide partial protection against declines in oil and natural gas prices, the total volumes we hedge are less than our expected production, vary from period to period based on our view of current and future market conditions, remain consistent with the requirements in effect under our Amended Term Loan Agreement and extend, on a rolling basis, for the next four years. These limitations result in our liquidity being susceptible to commodity price declines. Additionally, while intended to reduce the effects of volatile commodity prices, derivative transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the hedge. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change. We do not enter into derivative contracts for speculative trading purposes.

Recent Developments

Merger with Fury Resources.

On December 14, 2023, we entered into an Agreement and Plan of Merger, as amended (the “Merger Agreement”) with Fury Resources, Inc., a Delaware corporation (“Parent”) and San Jacinto Merger Sub, Inc. (“Merger Sub”), a Delaware corporation and a direct, wholly owned subsidiary of Parent.

The Merger Agreement provides, that upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into us (the “Merger”), with us surviving as a wholly owned subsidiary of Parent. Subject to the terms and conditions set forth in the Merger Agreement, at the effective time of the Merger, each of our issued and outstanding shares of Common Stock, par value $0.0001 per share (“Common Stock”) shall be converted into the right to receive $9.80 in cash, without interest, which represents a total transaction value of approximately $450. million (the “Merger Consideration”), and such shares shall otherwise cease to be outstanding, shall automatically be canceled and retired and cease to exist; and each outstanding share of redeemable convertible preferred stock will be contributed to Parent in exchange for new preferred shares of Parent, or sold to Parent for cash, in each case at valuation based on the conversion or redemption value of such preferred stock.

If the Merger is consummated, our shares of Common Stock will no longer trade on the NYSE American and will be deregistered under the Securities Exchange Act of 1934, as amended. As a result, we will become a private company.

On January 24, 2024, Parent and we agreed to cause an amount equal to $10.0 million to be distributed from the escrow account to the Company.

Conditions to Closing

The obligations of us, Parent and Merger Sub to consummate the Merger are subject to the satisfaction or waiver of certain customary closing conditions, including, among other things: (a) the absence of any law or order of any Governmental Authority having jurisdiction over a party to the Merger Agreement prohibiting or making illegal the consummation of the Merger, and (b) the adoption of the Merger Agreement by a majority vote of the issued and outstanding shares of Company Common Stock.

We have incurred approximately $3.2 million as of March 20, 2024, and will continue to incur significant costs and expenses, including fees for professional services and other transaction costs, in connection with the Merger.

Preferred Stock Equity Issuance. During the third quarter of 2023, we obtained an additional support letter from the Investors to purchase additional preferred equity securities in an amount up to $55.0 million over the next 12 months and an aggregate of 35,000 shares of preferred stock were sold on December 15, 2023 under such support letter to the Investors for proceeds of $34.1 million, net of $0.9 million of original issue discount.

At December 31, 2023, $20.0 million remained available for issuance under the support letter from the Investors. The issuances of preferred stock were approved by our board of directors upon recommendation by a special committee of disinterested directors that was established to evaluate the proposed terms of the preferred stock.

On March 27, 2024, we sold, in a private placement, the remaining 20,000 shares under the support letter to the Investors for proceeds of $19.5 million, net of $0.5 million of original issue discount.

Holders have no voting rights with respect to the shares of preferred stock. The preferred stock receives annual dividends, paid either in cash at a fixed rate of 14.5% annually or accrued at a fixed rate of 16.0% annually (“PIK accrual”) at our option. Currently, our Amended Term Loan Agreement prohibits the payment of cash dividends. Paid-in-kind (“PIK”) dividends are cumulative, compound and accrue quarterly in arrears and are added to the Liquidation Preference.

Shares of preferred stock will be convertible, subject to conversion ratios and prices stipulated in the agreement, at any time by the holders and by Battalion after meeting certain other agreement requirements. Battalion will also have the right to redeem the preferred stock in cash at an amount equal to between 100-120% of the Liquidation Preference ($1,000 per share, increased for any PIK accruals) determined according to the redemption date. Additionally, in the event of a change of control, holders have the right to receive, (i) at any time on or prior to 150 days following the closing date, and at the election of the Company, a cash payment equal to the Liquidation Preference or equity consideration equal to the 107.5% of the Liquidation Preference, or (ii) at any time after 150 days following the closing date, a cash payment equal to between 100-120% of the Liquidation Preference determined by the redemption date or conversion into common stock. Until (i) a termination of or certain amendments to the Amended Term Loan Agreement or (ii) one year past the maturity date of the Amended Term Loan Agreement, an election of the cash payment option by holders in a change of control scenario is not permitted. For additional information, see Item 8. *Consolidated Financial Statements and Supplementary Date – Note 11, Redeemable Convertible Preferred Stock.*

H2S Treating Joint Venture. In May 2022, we entered into a joint venture agreement with Caracara to develop the Facility in Winkler County, Texas. The joint venture, operating as WAT, also entered into a GTA with us for natural gas production from our Monument Draw area. In exchange for contributing to the joint venture a wellbore with an approved permit for the injection of acid gas and surface land , we retained a 5% equity interest in WAT, an unconsolidated subsidiary. Caracara provided the initial capital for the construction of the Facility, which is expected to have an initial capacity of approximately 30 MMcf per day, and a design capacity to treat up to 10% combined concentrations for H2S and CO2. We initially expected the AGI facility to be mechanically complete in early April 2023 and the facility to be in service in the second quarter of 2023. However, during commissioning and initial operations, it was determined that additional pressure was required to initiate gas injection. To correct this issue, a positive displacement pump was ordered and installed. The Facility's injection well also experienced pressure communication between the tubing and annular space after an injection procedure. We commenced workover operations to remediate this issue. During the third quarter of 2023, additional complications were encountered with the workover operation at the Facility causing higher than expected costs. To fund this workover operation, we advanced capital contributions totaling approximately $15.1 million during the year ended December 31, 2023 on behalf of our joint venture partner in WAT. Pursuant to the terms of the agreement governing the joint venture, we believe we have multiple remedies to recover such advance, including (1) declaring such payment a loan, which pursuant to the agreement would have an interest rate of the lesser of 15% or the maximum rate permitted by law, (2) recoupment from distributions from the joint venture and (3) reallocation of equity of the joint venture based on the relative level of total capital contributions by the parties after taking into account the advance. We advanced additional capital contributions on behalf of our joint venture partner during the first quarter of 2024 of approximately $3.0 million to fund WAT with the necessary capital required to complete the sidetrack of the AGI well.

All well work is currently complete, and our current forecast assumes the AGI facility will be processing 20,000 Mcf of natural gas per day in the second quarter of 2024. It is possible that the existing remedial facility work by WAT could extend past this estimate. Any delays in commissioning past the first quarter of 2024 will result in higher processing fees than currently forecasted until such time the Facility comes online.

Under the GTA, we will pay a treating rate that varies based on volumes delivered to the Facility for a term that will last 20 years from the in-service date of the Facility and have a minimum volume commitment of 20 MMcf per day, with certain rollover rights and start-up flexibility, for an initial term of five years from the in service date of the Facility, which can be extended up to seven years under certain conditions. Once in service, the GTA has a tiered-rate structure which is expected to drive a greater than 50 percent reduction in treating fees. Our current estimates of facility in-service dates and future treating fee reductions are subject to various operational and other risk factors, some of which are beyond our control, which could impact the timing and extent of these estimates.

Capital Resources and Liquidity

Overview. Our ability to execute our operating strategy is dependent on our ability to maintain adequate liquidity and access additional capital, as needed. Our future capital resources and liquidity depend, in part, on our success in developing our leasehold interests, growing our reserves and production and finding additional reserves. Sufficient levels of available cash are required to fund capital expenditures necessary to offset inherent declines in our production and proven reserves. As of December 31, 2023, we had $57.5 million of cash and cash equivalents, no additional borrowing capacity under our Amended Term Loan Agreement (in Item 8. *Consolidated Financial Statements and Supplementary Date – Note 6, Debt*) and a total of $50.0 million in debt repayments due under our Amended Term Loan Agreement through December 2024. At December 31, 2023, $20.0 million remained available for issuance under the support letter from the Investors.

Our Amended Term Loan Agreement contains certain restrictive covenants (namely our Current Ratio covenant) as well as a mandatory repayment schedule. We are required to make scheduled payments in the aggregate amount of $85.0 million from the fiscal quarter ending March 31, 2024 through the fiscal quarter ending September 30, 2025 with $10.0 million due at the end of the first quarter of 2024, $12.5 million due at the end of each of the second and third quarters of 2024, $15.0 million due at the end of the fourth quarter of 2024 and the first quarter of 2025, and $10.0 million due at the end of each of the second and third quarters of 2025. We will be required to make a final payment of $115.0 million at maturity on November 24, 2025.

In November 2022, we were required to seek an amendment to our Term Loan Agreement (as defined in Item 8. *Consolidated Financial Statements and Supplementary Date – Note 6, Debt)* to alleviate Current Ratio covenant compliance requirements through the first quarter of 2023 as a result of reduced commodity prices, higher interest rates, and the high capital costs experienced in our 2022 drilling program, which are by nature difficult to predict and subject to factors outside the Company's control. In the first quarter of 2023, commodity prices, cost conditions and interest rates continued to deteriorate, which further constrained our liquidity. As a result, we projected near-term future covenant breaches (specifically the Current Ratio) beginning with the first quarter of 2023, coupled with inadequate liquidity resources available to fully fund all of our upcoming obligations, including debt repayments and interest, capital expenditures and operating costs. In the absence of additional liquidity from other sources with agreeable economic terms, we obtained $95.6 million preferred equity funding from our three largest existing stockholders during 2023.

We have continued to execute on a plan to reduce operating and capital costs to improve cash flow, including a reduction in headcount in April 2023 to align with planned drilling activity and the issuance of preferred stock totaling $95.6 million during 2023. On March 27, 2024, we completed the sale of the additional $19.5 million of available preferred equity securities under the support letter from the Investors received in November 2023. Management believes that based upon its operational forecasts, cash and cash equivalents on hand, including the $10.0 million Initial Deposit Amount under the Merger Agreement, the March 2024 sale of $19.5 million in additional preferred equity and continued cost reduction measures, it is probable that we will have sufficient liquidity to fund our operations, meet our debt requirements and maintain compliance with our future debt covenants as described in Item 8. *Consolidated Financial Statements and Supplementary Date – Note 6, Debt* for the next 12 months from the issuance of these consolidated financial statements. We will, however, continue to pursue alternative liquidity sources which could include entering into other financing arrangements (e.g. future equity raises), a sale of a portion of our non-core assets, seeking capital partners for our drilling program, pursuing strategic merger opportunities or joint ventures, the sale of the Company, or pursuing additional general and administrative or other cost reduction opportunities. Our estimates and forecasts are based upon assumptions that may prove to be incorrect due to many factors that are currently unknown, such as prevailing economic conditions, many of which are beyond our control. In the event the assumptions underlying our estimates and forecasts prove to be incorrect, our operating plans, capital requirements, and covenant compliance may be adversely impacted.

In the event our cash flows are materially less than anticipated or our costs are materially greater than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may be required to curtail drilling, development, land acquisitions and other activities to reduce our capital spending. However, significant or prolonged reductions in capital spending will adversely impact our production and may negatively affect our future cash flows.

We continuously monitor changes in market conditions and will continue to adapt our operational plans as necessary to strive to maintain sufficient liquidity, facilitate drilling on our undeveloped acreage position and permit us to selectively expand our acreage, as well as meet our debt obligations and restrictive covenants. We have been, and continue to, explore strategic transactions to address these concerns, while also looking at opportunities to significantly reduce expenses in the near term. In this regard, we have considered whether it is advisable to continue to bear the ongoing costs of the listing of our common stock on the NYSE American and of being a reporting Company under the Securities Exchange Act of 1934. We believe that we currently qualify to suspend these obligations should we elect to do so. While such a determination has not yet been made, we expect that the cost savings, particularly over the longer term, would be significant. Accordingly, we will continue to consider the matter while we simultaneously pursue strategic and financial alternatives that may render it unnecessary. We will continue to pursue additional liquidity sources which could include entering into other financing arrangements (e.g. future equity raises), a sale of a portion of our non-core assets, for example deep rights, pursuing strategic merger opportunities or joint ventures, further reducing our discretionary capital program, or pursuing other general and administrative or other cost reduction opportunities including aligning our workforce headcount with planned drilling activity. However, there can be no assurance that, absent additional capital, reducing costs or other material favorable developments, the company will not experience liquidity and covenant compliance issues in the future.

Other Risks and Uncertainties. Our ability to complete transactions and maintain or increase our liquidity is subject to a number of variables, including our level of oil and natural gas production, proved reserves and commodity prices, the amount and cost of our indebtedness, as well as various economic and market conditions that have historically affected the oil and natural gas industry. Even if we are otherwise successful in growing our proved reserves and production, if oil and natural gas prices decline for a sustained period of time, our ability to fund our capital expenditures, complete acquisitions, reduce debt, meet our financial obligations and become profitable may be materially impacted.

Additionally, in periods of increasing commodity prices, we continue to be at risk to supply chain issues, including, but not limited to, labor shortages, pipe restrictions and potential delays in obtaining frac and/or drilling related equipment that could impact our business. During these periods, the costs and delivery times of rigs, equipment and supplies may also be substantially greater. The unavailability or high cost of drilling rigs and/or frac crews, pressure pumping equipment, tubulars and other supplies, and of qualified personnel can materially and adversely affect our operations and profitability.

Lastly, actual or anticipated declines in domestic or foreign economic activity or growth rates, regional or worldwide increases in tariffs or other trade restrictions, turmoil affecting the U.S. or global financial system and markets and a severe economic contraction either regionally or worldwide, resulting from international conflicts, efforts to contain pandemics or other factors, could materially affect our business and financial condition and impact our ability to finance operations by worsening the actual or anticipated future drop in worldwide oil demand, negatively impacting the price received for oil and natural gas production or adversely impacting our ability to comply with covenants in our Amended Term Loan Agreement. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our vendors and suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations. All of the foregoing may adversely affect our business, financial condition, results of operations, cash flows and, potentially, compliance with the covenants contained in our Amended Term Loan Agreement.

Capital Expenditures. During 2023, we spent approximately $46.6 million in capital expenditures, including drilling, completion, support infrastructure and other capital costs. During 2023, we ran one operated rig in the Delaware Basin. We drilled and completed 2 gross (2 net) operated wells and put online 3 gross (3 net) operated wells during the year.

Debt Obligations. On November 24, 2021, we and our wholly owned subsidiary, Halcón Holdings, LLC (‘ Borrower’), entered into a Term Loan Agreement with Macquarie Bank Limited, as administrative agent, and certain other financial institutions party thereto, as lenders. The Term Loan Agreement amended and restated in its entirety our previous revolving credit agreement entered into in 2019.

On November 14, 2022, we paid approximately $2.4 million and entered into the Amended Term Loan Agreement with our lenders which modified certain provisions of our original Term Loan Agreement and includes the maintenance of the following ratios (as defined in the Amended Term Loan Agreement):

- Asset Coverage Ratio of not less than 1.80 to 1.00 as of December 31, 2023 and the last day of each fiscal quarter thereafter,
- Total Net Leverage Ratio of not greater than 2.50 to 1.00 as of December 31, 2023 and each fiscal quarter thereafter, and
- Current Ratio of not less than 1.00 to 1.00, determined as of the last day of any fiscal quarter period, as of December 31, 2023 and each fiscal quarter thereafter.

We may elect, at our option, to prepay any borrowing outstanding under the Amended Term Loan Agreement subject to the following prepayment premiums:

Period (after applicable borrowing date [(1)])	Premium
Months 0 - 12	Make-whole amount equal to 12 months of interest plus 2.00%
Months 13 - 24	2.00%
Months 25 - 36	1.00%
Months 37 - 48	0.00%

(1) Applicable borrowing dates are November 2021 for the original $200.0 million borrowed and April and November 2022 for the $20.0 million and $15.0 million in delayed draw borrowings, respectively.

We may be required to make mandatory prepayments of the loans under the Amended Term Loan Agreement in connection with the incurrence of non-permitted debt, certain asset sales, and with cash on hand in excess of certain maximum levels beginning in 2023. For each fiscal quarter after January 1, 2023, we are required to make mandatory prepayments when the Consolidated Cash Balance, as defined in the Amended Term Loan Agreement, exceeds $20.0 million. Until December 31, 2024, the forecasted approved plan of development (“APOD”) capital expenditures for the succeeding fiscal quarter are excluded for purposes of determining the Consolidated Cash Balance. As of December 31, 2023, the Consolidated Cash Balance, as defined in the Amended Term Loan Agreement, did not exceed $20.0 million when considering forecasted APOD capital expenditures and cash held in unrestricted subsidiaries; therefore, no mandatory prepayment was necessary.

Our prepayment premiums would differ from those noted in the table above should a change of control result in prepayment within the second anniversary of the amendment date, as a 2% payment premium will apply.

As of December 31, 2023, we had $200.0 million of indebtedness outstanding and approximately $0.3 million of letters of credit outstanding under the Amended Term Loan Agreement. We currently, as of March 25, 2024, have $4.7 million available for the issuance of letters of credit. The maturity date of the Amended Term Loan Agreement is November 24, 2025.

We are required to make scheduled amortization payments in the aggregate amount of $85.0 million from the fiscal quarter ending March 31, 2024 through the fiscal quarter ending September 30, 2025 with $10.0 million due at the end of the first quarter of 2024, $12.5 million due at the end of each of the second and third quarters of 2024, $15.0 million due at the end of the fourth quarter of 2024 and the first quarter of 2025, and $10.0 million due at the end of each of the second and third quarters of 2025. We will be required to make a final payment of $115.0 million at maturity on November 24, 2025. Amounts outstanding under the Amended Term Loan Agreement are guaranteed by certain of the Borrower’s direct and indirect subsidiaries and secured by a security interest in substantially all of the assets of the Borrower and such direct and indirect subsidiaries, and of the equity interests of the Borrower held by us. As part of the Amended Term Loan Agreement there are certain restrictions on the transfer of assets, including cash, to Battalion from the guarantor subsidiaries.

As of December 31, 2023, the Company was in compliance with the financial covenants under the Amended Term Loan Agreement.

The Amended Term Loan Agreement also contains an APOD for our Monument Draw acreage through the drilling and completion of certain wells. The Term Loan Agreement contains a proved developed producing production test and an APOD economic test which we must maintain compliance with; otherwise, subject to any available remedies or waivers, we are required to immediately cease making expenditures in respect of the approved plan of development other than any expenditures deemed necessary by us in respect of no more than six additional approved plan of development wells.

The Amended Term Loan Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

Changes in the level and timing of our production, drilling and completion costs, the cost and availability of transportation for our production and other factors varying from our expectations can affect our ability to comply with the covenants under our Amended Term Loan Agreement. As a consequence, we endeavor to anticipate potential covenant compliance issues and work with our lenders to address any such issues ahead of time.

While we have largely been successful in obtaining modifications of our covenants as needed, as evidenced most recently by the amendment of our Term Loan Agreement in November 2022 which reduced the Current Ratio covenant as of September 30, 2022 through March 31, 2023, there can be no assurance that we will be successful in the future. In the event we are not successful in obtaining covenant modifications, if needed, there is no assurance that we will be successful in implementing alternatives that allow us to maintain compliance with our covenants or that we will be successful in obtaining alternative financing that provides us with the liquidity that we need to operate our business. Even if successful, alternative sources of financing could prove more expensive than borrowings under our Amended Term Loan Agreement.

The results presented in this Form 10-K are not necessarily indicative of future operating results. For further information regarding these risks and uncertainties on us, see *"Risk Factors"* in Item 1A of this Annual Report on Form 10-K.

Cash Flow. Net increase (decrease) in cash, cash equivalents and restricted cash is summarized as follows for the periods presented (in thousands):

	Years Ended December 31,	
	2023	**2022**
Cash flows provided by operating activities	$ 17,589	$ 78,801
Cash flows used in investing activities	(51,845)	(126,130)
Cash flows provided by financing activities	59,059	31,786
Net increase (decrease) in cash, cash equivalents and restricted cash	$ 24,803	$ (15,543)

Operating Activities. Net cash flows provided by operating activities for the years ended December 31, 2023 and 2022 were $17.6 million and $78.8 million, respectively. Items impacting the reduction in operating cash flows were (i) lower total operating revenues resulting from an approximate $20.00 per Boe decrease in average realized prices (excluding the impact of hedging arrangements) for the year ended December 31, 2023 compared to the year ended December 31, 2022, (ii) increased operating and interest costs in 2023, and (iii) changes in working capital.

Investing Activities. Net cash flows used in investing activities for the years ended December 31, 2023 and 2022 were approximately $51.8 million and $126.1 million, respectively.

During the year ended December 31, 2023, we spent $46.3 million on oil and natural gas capital expenditures, of which $40.4 million related to drilling and completion costs and $4.7 million related to the development of our treating equipment and gathering support infrastructure.

During the year ended December 31, 2022, we spent $125.5 million on oil and natural gas capital expenditures, of which $108.3 million related to drilling and completion costs and $13.7 million related to the development of our treating equipment and gathering support infrastructure.

Financing Activities. Net cash flows provided by financing activities for the years ended December 31, 2023 and 2022 were approximately $59.1 million and $31.8 million, respectively. During the year ended December 31, 2023, we received $95.6 million in proceeds from the sales and issuance of preferred stock and we made $35.0 million of repayments under our Amended Term Loan Agreement.

During the year ended December 31, 2022, we borrowed the remaining $35.0 million available under the Amended Term Loan Agreement and paid approximately $2.9 million in deferred financing costs, including $2.4 million upon entering into the Amended Term Loan Agreement with its lenders in November 2022.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Activities

Full Cost Method

We use the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized into a cost center (the amortization base or full cost pool). Such amounts include the cost of drilling and equipping productive wells, treating equipment and gathering support facilities costs, dry hole costs, lease acquisition costs and delay rentals. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our evaluated oil and natural gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depletion, depreciation and accretion expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2023 and 2022 were prepared by NSAI, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. *Consolidated Financial Statements and Supplementary Data —"Supplemental Oil and Gas Information (Unaudited).*"

Depletion Expense

Our rate of recording depletion expense is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record depletion expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. At December 31, 2023, a five percent positive revision to proved reserves would decrease the depletion rate by approximately $0.50 per Boe and a five percent negative revision to proved reserves would increase the depletion rate by approximately $0.56 per Boe.

Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and could result in lower amortization expense in future periods. The present value of our estimated proved reserves (discounted at 10%) is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, it is possible that write-downs of our oil and natural gas properties could occur in the future. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties to our full cost pool, capital spending and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Using the first-day-of-the-month average for the 12-months ended December 31, 2023 of the WTI crude oil spot price of $78.21 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first-day-of-the-month average for the 12-months ended December 31, 2023 of the Henry Hub natural gas price of $2.64 per MMBtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials, our ceiling test calculation would not have generated an impairment at December 31, 2023, holding all other inputs and factors constant. Additionally, a 10% reduction in respective commodity prices at December 31, 2023, while all other factors remained constant, would not have generated an impairment.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production facility, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. At December 31, 2023, a five percent increase in future development and abandonment costs would increase the depletion rate by approximately $0.31 per Boe and a five percent decrease in future development and abandonment costs would decrease the depletion rate by $0.31 per Boe.

Accounting for Derivative Instruments and Hedging Activities

We account for our derivative activities under the provisions of the Financial Accounting Standards Board's (the "FASB") Accounting Standards Codification ("ASC" Topic 815, *Derivatives and Hedging* ("ASC 815"). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, in accordance with our policy, we may hedge a portion of our forecasted oil and natural gas production. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

Income Taxes

Our provision for taxes includes both state and federal taxes. We account for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. We classify all deferred tax assets and liabilities, along with any related valuation allowance, as noncurrent on the consolidated balance sheets.

In assessing the need for a valuation allowance on our deferred tax assets, we consider possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies. We consider all available evidence (both positive and negative) in determining whether a valuation allowance is required. Based upon the evaluation of available evidence, a valuation allowance of $425.0 million has been applied against our deferred tax asset balance as of December 31, 2023.

ASC Topic 740, *Income Taxes* ("ASC 740") creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

Results of Operations

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

The table below set forth financial information for the periods presented.

In thousands (except per unit and per Boe amounts)	Years Ended December 31, 2023	Years Ended December 31, 2022
Operating revenues:		
Oil	$ 183,634	$ 267,690
Natural gas	11,057	46,210
Natural gas liquids	23,814	43,501
Other	2,257	1,663
Total operating revenues	220,762	359,064
Operating expenses:		
Production:		
Lease operating	44,864	48,095
Workover and other	7,149	6,683
Taxes other than income	11,943	18,483
Gathering and other	63,575	64,117
General and administrative:		
General and administrative	20,095	15,425
Stock-based compensation	(1,070)	2,210
Depletion, depreciation and accretion:		
Depletion – Full cost	55,179	51,020
Depreciation – Other	652	367
Accretion expense	793	528
Other income (expenses):		
Net gain (loss) on derivative contracts	12,689	(110,006)
Interest expense and other	(33,319)	(23,591)
Net (loss) income	$ (3,048)	$ 18,539
Production:		
Crude oil – MBbls	2,415	2,837
Natural gas – MMcf	8,718	9,337
Natural gas liquids – MBbls	1,163	1,242
Total MBoe(1)	5,031	5,635
Average daily production – Boe(1)	13,784	15,438
Average price per unit (2):		
Crude oil price - Bbl	$ 76.04	$ 94.36
Natural gas price - Mcf	1.27	4.95
Natural gas liquids price - Bbl	20.48	35.02
Total per Boe(1)	43.43	63.43
Average cost per Boe:		
Production:		
Lease operating	$ 8.92	$ 8.54
Workover and other	1.42	1.19
Taxes other than income	2.37	3.28
Gathering and other	12.64	11.38
Restructuring	—	—
General and administrative:		
General and administrative	3.99	2.74
Stock-based compensation	(0.21)	0.39
Depletion	10.97	9.05

(1) *Determined using a ratio of six Mcf of natural gas to one barrel of oil, condensate, or NGLs based on approximate energy equivalency. This is an energy content correlation and does not reflect the value or price relationship between the commodities.*

(2) *Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.*

Operating Revenues. Oil, natural gas and natural gas liquids revenues were $218.5 million and $357.4 million for the years ended December 31, 2023 and 2022, respectively. The decrease of $138.9 million in revenue is primarily attributable to a decrease in average realized prices and lower production volumes in 2023 compared to 2022. The decrease is comprised of $38.3 million due to lower production volumes and $100.6 million due to lower average realized prices. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, transportation take-away capacity constraints, inventory storage levels, quality of production, basis differentials and other factors.

Production for the years ended December 31, 2023 and 2022 averaged 13,784 Boe/d and 15,438 Boe/d, respectively. Production is lower in 2023 compared with 2022 in total due largely to the timing of capital expenditures spent to bring new wells online and natural production declines on our existing producing wells. In 2023, we have put online 3 gross (3 net) operated wells while in 2022 we put online 9 gross (8.5 net) operated wells. In addition, 2 of the 3 operated wells we put online in 2023 were put online at the end of December. As such, these wells had minimal impact on 2023 productions. Also impacting 2023 production volumes was curtailment in Monument Draw in the second half of the year due to downstream throughput limitations.

Lease Operating Expenses. Lease operating expenses were $44.9 million and $48.1 million for the years ended December 31, 2023 and 2022, respectively. On a per unit basis, lease operating expenses were $8.92 per Boe and $8.54 per Boe for the years ended December 31, 2023 and 2022, respectively. The decrease in lease operating expenses in 2023 results primarily from lower production in 2023 compared to 2022 while the increase year over year in lease operating expenses on a per unit basis is primarily a result of an inflationary market increase in maintenance, power, and chemical costs.

Workover and Other Expenses. Workover and other expenses were $7.2 million and $6.7 million for the years ended December 31, 2023 and 2022, respectively. On a per unit basis, workover and other expenses were $1.42 per Boe and $1.19 per Boe for the year ended December 31, 2023 and 2022, respectively. The increased workover and other expenses in 2023 relate to more significant workover projects undertaken in the current year as well as inflationary market increases in service and material costs in 2023.

Taxes Other than Income. Taxes other than income were $11.9 million and $18.5 million for the years ended December 31, 2023 and 2022, respectively. Most production taxes are based on production volumes and realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease. On a per unit basis, taxes other than income were $2.37 per Boe and $3.28 per Boe for the years ended December 31, 2023 and 2022, respectively.

Gathering and Other Expenses. Gathering and other expenses were $63.6 million ($12.64 per Boe) and $64.1 million ($11.38 per Boe) for the years ended December 31, 2023 and 2022, respectively. Our gathering and other expenses are primarily driven by the amount and location of natural gas production, the concentration of H_2S in our sour gas produced, and the amounts paid to treat our sour gas volumes, either through our own hydrogen sulfide treating plant or through third parties. For the year ended December 31, 2023, overall natural gas production volumes slightly decreased compared to 2022; however, a higher concentration of sour natural gas in our Monument Draw area requiring H_2S treatment in 2023 contributed to higher gathering and other expenses on a per unit basis compared to 2022.

General and Administrative Expense. General and administrative expense was $20.1 million and $15.4 million for the years ended December 31, 2023 and 2022, respectively. The increase in general and administrative expense for 2023 is primarily associated with an increase in professional fees and nonrecurring costs related to the merger partially offset by a decrease in payroll and employee benefits. On a per unit basis, general and administrative expense were $3.99 per Boe and $2.74 per Boe for the years ended December 31, 2023 and 2022, respectively.

Depletion, Depreciation, and Amortization Expense. Depletion for oil and natural gas properties is calculated using the unit-of-production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. Depletion expense was $55.2 million and $51.0 million for the years ended December 31, 2023 and 2022, respectively. On a per unit basis, depletion expense was $10.97 per Boe and $9.05 per Boe for the years ended December 31, 2023 and 2022, respectively. The increase in our depletion rate for the year ended December 31, 2023 compared to 2022 is primarily due to decreased proved reserves relative to the change in future development costs associated with those proved reserves when comparing 2023 to 2022.

Net gain (loss) on derivative contracts . We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes. Accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. We recorded a net derivative gain of $12.7 million ($21.9 million net gain on unsettled contracts and $9.2 million net loss on settled contracts) for the year ended December 31, 2023. We recorded a net derivative loss of $110.0 million ($20.3 million net gain on unsettled contracts and $130.3 million net loss on settled contracts) for the year ended December 31, 2022. At December 31, 2023, we had a $13.9 million derivative asset, $9.0 million of which was classified as current, and we had a $33.3 million derivative liability, $17.2 million of which was classified as current.

Interest Expense and Other. Interest expense and other was $33.3 million and $23.6 million for the years ended December 31, 2023 and 2022, respectively. Interest expense and other increased in the current year due primarily to increased interest rates and amortization/accretion of financing related costs associated with our amendment to the Amended Term Loan Agreement entered into in November 2022. Our weighted average interest rate for the year ended December 31, 2023, was approximately 12.68%. For the first quarter of 2024, we anticipate our interest rate will be 12.99% on outstanding borrowings.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 1, "*Summary of Significant Events and Accounting Policies* ."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivative Instruments and Hedging Activity

We are exposed to various risks, including energy commodity price risk, such as price differentials between the NYMEX commodity price and the index price at the location where our production is sold. When oil and natural gas prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include fixed-price swaps, costless collars, basis swaps and WTI NYMEX rolls. The total volumes that we hedge through the use of our derivative instruments varies from period to period, however, our requirement under our Amended Term Loan Agreement, is to hedge approximately 50% to 85% of our anticipated oil and natural gas production, in varying percentages by year, on a rolling basis for the next four years, when derivative contracts are available at terms and prices acceptable to us. Our hedge policies and objectives may change significantly as our operational profile and contractual obligations change but remain consistent with the requirements in effect under our Amended Term Loan Agreement. We do not enter into derivative contracts for speculative trading purposes.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competitive market makers. As of December 31, 2023, we did not post collateral under any of our derivative contracts as they are secured under our Amended Term Loan Agreement.

We account for our derivative activities under the provisions of ASC Topic 815, *Derivatives and Hedging*, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Item 8. *Consolidated Financial Statements and Supplementary Data* —Note 7, *"Derivative and Hedging Activities,"* for more details.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, restricted cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. *Consolidated Financial Statements and Supplementary Data*—Note 7, "*Fair Value Measurements,"* for additional information.

Interest Rate Sensitivity

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are SOFR (and previously, LIBOR) based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At December 31, 2023, the principal amount of our debt was $200.00 million, of which substantially all bears interest at floating and variable interest rates that are tied to SOFR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At December 31, 2023, the weighted average interest rate on our variable rate debt was 12.99% per year. If the balance of our variable interest rate debt at December 31, 2023 were to remain constant, a 10% change in market interest rates would impact our cash flows by approximately $2.6 million per year.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Battalion Oil Corporation (the Company), including the Company's Chief Executive Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company's internal control system was designed to provide reasonable assurance to the Company's Management and Board of Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on this evaluation, Management concluded that Battalion Oil Corporation's internal control over financial reporting was effective as of December 31, 2023.

This Annual Report on Form 10-K does not include an attestation report of the Company's independent registered public accounting firm regarding the effectiveness of the Company's internal control over financial reporting. Management's report was not subject to attestation by its independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit smaller reporting companies to provide only Management's report in this Annual Report on Form 10-K.

/s/ MATTHEW B. STEELE
Matthew B. Steele
Chief Executive Officer
(Principal Executive Officer and Principal Financial Officer)

Houston, Texas
March 29, 2024

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Battalion Oil Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Battalion Oil Corporation and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, stockholders’ equity, and cash flows, for each of the two years in the period ended December 31, 2023, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Proved Oil and Natural Gas Property and Depletion — Oil and Natural Gas Reserve Quantities — Refer to Note 1 and 5 to the financial statements

Critical Audit Matter Description

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. The Company's proved oil and natural gas properties are depleted using the units of production method and are evaluated for impairment by the full cost ceiling impairment test utilizing the Company's oil and natural gas reserves in accordance with accounting principles generally accepted in the United States and SEC guidelines. The development of the Company's oil and natural gas reserve quantities and the related net present value of future cash flows from the related proved reserves requires management to make significant estimates and assumptions related to the future production to be obtained from proved reserves, the intent and ability to complete proved undeveloped reserves within a five-year development period as prescribed by SEC guidelines, and the future development costs associated with proved undeveloped reserves. The Company engages an independent reservoir engineering firm, management's specialist, to estimate oil and natural gas quantities using these assumptions and engineering data. Changes in these assumptions or engineering data could have a significant impact on the amount of depletion and impairment recorded for the Company's proved oil and natural gas properties.

Given the significant judgments made by management and management's specialist, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities and the related net cash flows, including management's estimates and assumptions related to future proved reserves production volumes, the intent and ability to complete proved undeveloped reserves within the five-year development period, and future development costs, requires a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures of management's significant judgments and assumptions related to oil and natural gas reserves quantities and estimates of the future net cash flows included the following, among others:

- We evaluated the reasonableness of management's five-year development plan by comparing the forecasts to:
  - Historical conversions of proved undeveloped oil and natural gas reserves into proved developed oil and natural gas reserves.
  - Internal communications to management and the Board of Directors.
  - Prior year Reserve Reports to evaluate whether the forecasted date of development for each proved undeveloped location is within five years of the date of its original inclusion in proved reserves.
  - The financial ability of the Company to execute its drilling program.
- We evaluated the reasonableness of management's estimate of future development costs by comparing the estimate to:
  - Historical development of similar wells, including location of the well.
  - Internal data and internal communications to management and the Board of Directors.
  - Approval for expenditures.

- We evaluated the reasonableness of management's estimated reserve quantities by performing the following:
    - Evaluating the experience, qualifications and objectivity of management's specialist, an independent reservoir engineering firm.
    - Performing analytical procedures on the reserve quantities developed by management's specialist.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 29, 2024

We have served as the Company's auditor since 2012.

BATTALION OIL CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31, 2023	2022
Operating revenues:		
Oil, natural gas and natural gas liquids sales:		
Oil	$ 183,634	$ 267,690
Natural gas	11,057	46,210
Natural gas liquids	23,814	43,501
Total oil, natural gas and natural gas liquids sales	218,505	357,401
Other	2,257	1,663
Total operating revenues	220,762	359,064
Operating expenses:		
Production:		
Lease operating	44,864	48,095
Workover and other	7,149	6,683
Taxes other than income	11,943	18,483
Gathering and other	63,575	64,117
General and administrative	19,025	17,635
Depletion, depreciation and accretion	56,624	51,915
Total operating expenses	203,180	206,928
Income from operations	17,582	152,136
Other income (expenses):		
Net gain (loss) on derivative contracts	12,689	(110,006)
Interest expense and other	(33,319)	(23,591)
Total other income expenses	(20,630)	(133,597)
(Loss) income before income taxes	(3,048)	18,539
Income tax benefit (provision)	—	—
Net (loss) income	$ (3,048)	$ 18,539
Series A preferred dividends	(12,047)	—
Net (loss) income available to common stockholders	$ (15,095)	$ 18,539
Net (loss) income per share of common stock:		
Basic	$ (0.92)	$ 1.14
Diluted	$ (0.92)	$ 1.12
Weighted average common shares outstanding:		
Basic	16,441	16,331
Diluted	16,441	16,510

The accompanying notes are an integral part of these consolidated financial statements.

BATTALION OIL CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31, 2023	December 31, 2022
Current assets:		
Cash and cash equivalents	$ 57,529	$ 32,726
Accounts receivable, net	23,021	37,974
Assets from derivative contracts	8,992	16,244
Restricted cash	90	90
Prepaids and other	907	1,131
Total current assets	90,539	88,165
Oil and natural gas properties (full cost method):		
Evaluated	755,482	713,585
Unevaluated	58,909	62,621
Gross oil and natural gas properties	814,391	776,206
Less - accumulated depletion	(445,975)	(390,796)
Net oil and natural gas properties	368,416	385,410
Other operating property and equipment:		
Other operating property and equipment	4,640	4,434
Less - accumulated depreciation	(1,817)	(1,209)
Net other operating property and equipment	2,823	3,225
Other noncurrent assets:		
Assets from derivative contracts	4,877	5,379
Operating lease right of use assets	1,027	352
Other assets	17,656	2,827
Total assets	$ 485,338	$ 485,358
Current liabilities:		
Accounts payable and accrued liabilities	$ 66,525	$ 100,095
Liabilities from derivative contracts	17,191	29,286
Current portion of long-term debt	50,106	35,067
Operating lease liabilities	594	352
Asset retirement obligations	—	225
Total current liabilities	134,416	165,025
Long-term debt, net	140,276	182,676
Other noncurrent liabilities:		
Liabilities from derivative contracts	16,058	33,649
Asset retirement obligations	17,458	15,244
Operating lease liabilities	490	—
Other	2,084	4,136
Commitments and contingencies (Note 10)		
Temporary equity:		
Series A redeemable convertible preferred stock: 98,000 shares of $ 0.0001 par value authorized, issued and outstanding as of December 31, 2023	106,535	—
Stockholders' equity:		
Common stock: 100,000,000 shares of $ 0.0001 par value authorized; 16,456,563 and 16,344,815 shares issued and outstanding as of December 31, 2023 and 2022, respectively	2	2
Additional paid-in capital	321,012	334,571
Accumulated deficit	(252,993)	(249,945)
Total stockholders' equity	68,021	84,628
Total liabilities and stockholders' equity	$ 485,338	$ 485,358

The accompanying notes are an integral part of these consolidated financial statements.

BATTALION OIL CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Stockholders' Equity
	Shares	Amount			
Balances at December 31, 2021	16,274	$ 2	$ 332,187	$ (268,484)	$ 63,705
Net income	—	—	—	18,539	18,539
Long-term incentive plan vestings	98	—	—	—	—
Tax withholding on vesting of restricted stock units	(28)	—	(493)	—	(493)
Stock-based compensation	1	—	2,877	—	2,877
Balances at December 31, 2022	16,345	2	334,571	(249,945)	84,628
Net loss	—	—	—	(3,048)	(3,048)
Deemed dividends for Series A preferred stock	—	—	(12,047)	—	(12,047)
Long-term incentive plan vestings	159	—	—	—	—
Tax withholding on vesting of restricted stock units	(47)	—	(453)	—	(453)
Stock-based compensation and other	—	—	(1,059)	—	(1,059)
Balances at December 31, 2023	16,457	$ 2	$ 321,012	$ (252,993)	$ 68,021

The accompanying notes are an integral part of these consolidated financial statements.

BATTALION OIL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31, 2023	Years Ended December 31, 2022
Cash flows from operating activities:		
Net (loss) income	$ (3,048)	$ 18,539
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depletion, depreciation and accretion	56,624	51,915
Stock-based compensation, net	(1,070)	2,210
Unrealized gain on derivative contracts	(21,934)	(20,256)
Amortization/accretion of financing related costs	7,615	5,448
Reorganization items, net	—	(744)
Accrued settlements on derivative contracts	259	4,302
Change in fair value of embedded derivative liability	(2,052)	(1,819)
Other expense (income)	358	(77)
Change in assets and liabilities:		
Accounts receivable	15,658	594
Prepaids and other	202	234
Accounts payable and accrued liabilities	(35,023)	18,455
Net cash provided by operating activities	17,589	78,801
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(46,288)	(125,465)
Proceeds received from sales of oil and natural gas assets	4,929	332
Other operating property and equipment capital expenditures	(153)	(1,160)
Contract asset	(10,308)	—
Other	(25)	163
Net cash used in investing activities	(51,845)	(126,130)
Cash flows from financing activities:		
Proceeds from borrowings	—	35,200
Repayments of borrowings	(35,093)	(95)
Payment of deferred financing costs	—	(2,887)
Proceeds from issuance of preferred stock	94,607	—
Other	(455)	(432)
Net cash provided by financing activities	59,059	31,786
Net increase (decrease) in cash, cash equivalents and restricted cash	24,803	(15,543)
Cash, cash equivalents and restricted cash at beginning of period	32,816	48,359
Cash, cash equivalents and restricted cash at end of period	$ 57,619	$ 32,816
Supplemental cash flow information:		
Cash paid for interest	$ 28,709	$ 19,933
Cash paid for reorganization items	—	744
Disclosure of non-cash investing and financing activities:		
Asset retirement obligations	$ 1,308	$ 3,692
Accrued capital expenditures	(4,381)	14,883
Contract asset costs in accounts payable and accrued liabilities	4,753	—
Deemed dividends on Series A preferred stock	12,047	—
Accrued offering costs	(119)	—

The accompanying notes are an integral part of these consolidated financial statements.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

Battalion Oil Corporation (“Battalion” or the “Company”) is the successor reporting company to Halcón Resources Corporation (Halcón). On January 21, 2020, Battalion filed a Certificate of Amendment to the Company’s Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to effect a change of the Company’s corporate name from Halcón Resources Corporation to Battalion Oil Corporation.

Battalion is an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. The Company operates in one reportable segment which focuses on oil and natural gas acquisition, production, exploration and development. Allocation of capital is made across the Company’s entire portfolio without regard to operating area. All intercompany accounts and transactions have been eliminated. The Company has evaluated events and transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

Use of Estimates

The preparation of the Company’s consolidated financial statements in conformity with GAAP requires the Company’s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas revenue accruals, capital and operating expense accruals, oil and natural gas reserves, depletion relating to oil and natural gas properties, asset retirement obligations, and fair value estimates. The Company bases its estimates and judgments on historical experience and on various other assumptions and information believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be predicted with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company’s operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company’s consolidated financial statement and the results presented in this Annual Report on Form 10-K are not necessarily indicative of future operating results.

Cash, Cash Equivalents and Restricted Cash

The Company considers all highly liquid short-term investments with a maturity of three months or less at the time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value. Amounts in the consolidated balance sheets included in “*Cash and cash equivalents*” and “*Restricted cash*” reconcile to the Company’s consolidated statements of cash flows as follows:

	December 31, 2023	December 31, 2022
Cash and cash equivalents	$ 57,529	$ 32,726
Restricted cash	90	90
Total cash, cash equivalents and restricted cash	$ 57,619	$ 32,816

Restricted cash consists primarily of funds to collateralize letters of credit outstanding.

Accounts Receivable and Allowance for Doubtful Accounts

The Company’s accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivable are recorded at the amount due, less an allowance for doubtful accounts, when applicable. Payment of the Company's accounts receivable is typically received within 30-60 days. The Company's historical credit losses have been de minimis and are expected to remain so in the future assuming no substantial changes to the business or creditworthiness of the Company's counterparties.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as prescribed by the United States Securities and Exchange Commission (the "SEC"). Accordingly, all costs incurred in the acquisition, exploration and development of proved and unproved oil and natural gas properties, including the costs of abandoned properties, treating equipment and gathering support facilities, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to estimated proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on estimated proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs are charged to expense.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company reviews its unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization. Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The Company determines capitalized interest, when applicable, by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that were excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The Company's accounting policy on the capitalization of interest establishes thresholds for the determination of a development project for the purpose of interest capitalization.

Additionally, the Company assesses all properties classified as unevaluated property on a quarterly basis for possible impairment. The Company assesses properties on an individual basis or as a group, if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the full cost ceiling test limitation.

Other Operating Property and Equipment

Other operating property and equipment are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: buildings, twenty years ; automobiles and computers, three years ; computer software, fixtures, furniture and equipment, five years ; trailers, seven years ; heavy equipment, eight to ten years and leasehold improvements, lease term. Land and artwork are not depreciated. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life or productive capacity of an asset are capitalized and depreciated over the estimated remaining useful life of the asset.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

The Company reviews its other operating property and equipment for impairment in accordance with the Financial Accounting Standards Board's (the "FASB") Accounting Standards Codification ("ASC") Topic 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate other operating property and equipment for impairment as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its other operating property and equipment at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Concentrations of Credit Risk

The Company's primary concentrations of credit risk are the risks of uncollectible accounts receivable and of nonperformance by two counterparties under the Company's derivative contracts. Each reporting period, the Company assesses the recoverability of material receivables using historical data, current market conditions and reasonable and supportable forecasts of future economic conditions to determine expected collectability of its material receivables.

The Company's accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts from its oil and natural gas purchasers. In 2023, two individual purchasers of the Company's production, Western Refining Company L.P. and Sunoco Inc., each accounted for more than 10 % of total sales, collectively representing 79 % of its total sales for the year. In 2022, three individual purchasers of the Company's production, Western Refining Company L.P., Sunoco Inc. and Targa Resources Inc., each accounted for more than 10 % of total sales, collectively representing 82 % of its total sales for the year.

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and natural gas producers. Joint operating agreements govern the operations of an oil or natural gas well and, in most instances, provide for offsetting of amounts payable or receivable between the Company and its joint interest owners. If the oil and natural gas exploration and production industry in general was adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The Company's exposure to credit risk under its derivative contracts is varied among major financial institutions with investment grade credit ratings, where it has master netting agreements which provide for offsetting of amounts payable or receivable between the Company and the counterparty. To manage counterparty risk associated with derivative contracts, the Company selects and monitors counterparties based on an assessment of their financial strength and/or credit ratings. At December 31, 2023, the Company's derivative counterparties include two major financial institutions, both of which are secured lenders under the Amended Term Loan Agreement.

Risk Management Activities

From time to time, in accordance with the Company's policy, it may hedge a portion of its forecasted oil and natural gas production. The Company recognized all derivative instruments as either assets or liabilities in the consolidated balance sheets at fair value. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations.

Income Taxes

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company classifies all deferred tax assets and liabilities, along with any related valuation allowance, as noncurrent on the consolidated balance sheets.

The evaluation of a tax position in accordance with ASC Topic 740, *Income Taxes* ("ASC 740") is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

Asset Retirement Obligations

The Company records asset retirement obligations ("AROs") to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells, treating equipment and gathering support facilities. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells, treating equipment and gathering support facilities as these obligations are incurred.

The Company records the ARO liability on the consolidated balance sheets and capitalizes the cost in *"Oil and natural gas properties"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and accretion"* expense in the consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis.

Recently Issued Accounting Pronouncements

In March 2020, the FASB issued Accounting Standards Update ("ASU") No. 2020-04, *Reference Rate Reform (Topic 848)* ("ASU 2020-04"), in response to the risk of cessation of the London Interbank Offered Rate ("LIBOR"). This amendment provides optional expedients and exceptions for applying generally accepted accounting principles to contracts, hedging arrangements, and other transactions that reference LIBOR. On December 21, 2022, the FASB issued ASU No. 2022-06, "*Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848* " ("ASU 2022-06"). ASU 2022-06 defers the sunset date from December 31, 2022, to December 31, 2024. As of the date of this filing, neither ASU 2020-04 nor ASU 2022-06 had a material impact on the Company's operating results, financial position or disclosures.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

In the first quarter of 2023, the Company early adopted the FASB's ASU 2020-06, *Debt – Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815-40) ("ASU 2020-06")*. The update simplifies the accounting for convertible debt instruments and convertible preferred stock by reducing the number of accounting models and limiting the number of embedded conversion features separately recognized from the primary contract. The guidance also includes targeted improvements to the disclosures for convertible instruments and earnings per share. The adoption of ASU 2020-06 did not have an impact on the Company's financial statements.

In November 2023, the FASB issued ASU 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures* ("ASU 2023-07"), which requires an entity, even one with only one reportable segment, to disclose significant segment expenses and other segment items on an annual and interim basis, and provide in interim periods all disclosures about a reportable segment's profit or loss and assets that are currently required annually. Additionally, it requires an entity to disclose the title and position of the chief operating decision maker. ASU 2023-07 does not change how an entity identifies its operating segments, aggregates them or applies the quantitative thresholds to determine its reportable segments. ASU 2023-07 is effective for fiscal years beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. Entities should apply the amendments in ASU 2023-07 retrospectively to all prior periods presented in the financial statements. We are currently evaluating the impact of adopting ASU 2023-07 and we expect limited impact on our disclosures with no impact to our consolidated financial statements upon adoption.

In December 2023, the FASB issued ASU 2023-09, *Income Taxes (Topic 740): Improvements to Income Tax Disclosures* ("ASU 2023-09"), which focuses on the income tax rate reconciliation and income taxes paid. ASU 2023-09 requires an entity to disclose, on an annual basis, a tabular rate reconciliation using both percentages and currency amounts, broken out into specified categories, with certain reconciling items further broken out by nature and jurisdiction to the extent those items exceed a specified threshold. In addition, entities are required to disclose income taxes paid, net of refunds received disaggregated by federal, state/local, and foreign, and by jurisdiction if the amount is at least 5% of total income tax payments, net of refunds received. ASU 2023-09 is effective for annual periods beginning after December 15, 2024, with early adoption permitted. An entity may apply the amendments in ASU 2023-09 prospectively by providing the revised disclosures for the period ending December 31, 2025 and continuing to provide the pre-ASU disclosures for the prior periods, or may apply the amendments retrospectively by providing the revised disclosures for all period presented. We are currently evaluating the impact of adopting ASU 2023-09 but do not expect it to have a material impact on our disclosures, with no impact to our results of operations, cash flows, or financial condition.

2. MERGER AGREEMENT

Agreement and Plan of Merger

On December 14, 2023, the Company entered into an Agreement and Plan of Merger, as amended (the "Merger Agreement") with Fury Resources, Inc., a Delaware corporation ("Parent") and San Jacinto Merger Sub, Inc. ("Merger Sub"), a Delaware corporation and a direct, wholly owned subsidiary of Parent. The Merger Agreement provides, that upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into the Company (the "Merger"), with the Company surviving as a wholly owned subsidiary of Parent. Subject to the terms and conditions set forth in the Merger Agreement, each of the Company's issued and outstanding shares of Common Stock, par value $ 0.0001 per share ("Common Stock") shall be converted into the right to receive $ 9.80 in cash, without interest, which represents a total transaction value of approximately $ 450.0 million, and such shares shall otherwise cease to be outstanding, shall automatically be canceled and retired and cease to exist; and each outstanding share of redeemable convertible preferred stock will be contributed to Parent in exchange for new preferred shares of Parent , or sold to Parent for cash, in each case at a valuation based on the conversion or redemption value of such preferred stock.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

On January 24, 2024, Parent and the Company agreed to cause an amount equal to $ 10.0 million to be distributed from the escrow account to the Company.

The obligations of the Company, Parent and Merger Sub to consummate the Merger are subject to the satisfaction or waiver of certain customary closing conditions, including, among other things: (a) the absence of any law or order of any Governmental Authority having jurisdiction over a party to the Merger Agreement prohibiting or making illegal the consummation of the Merger, and (b) the adoption of the Merger Agreement by a majority vote of the issued and outstanding shares of Company Common Stock.

3. LEASES

The Company leases equipment and office space pursuant to operating leases. The Company determines if an arrangement is or contains a lease at inception and combines lease and nonlease components, when fixed, for all lease contracts. Nonlease components include common area maintenance charges on office leases and, when applicable, services associated with equipment leases. Operating leases with a lease term greater than 12 months where the Company is the lessee are included in *"Operating lease right of use assets"* and *"Operating lease liabilities"* on the consolidated balance sheets and recorded based on the present value of the future minimum lease payments over the lease term. As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at the commencement date to determine the present value of lease payments. The Company does not recognize right of use assets and lease liabilities for short-term leases that have a lease term of 12 months or less, but rather recognizes the lease payments associated with its short-term leases when incurred.

Payments due under the lease contracts include fixed payments plus, in some instances, variable payments. Variable lease payments, if applicable, associated with the Company's leases are recognized when the event, activity, or circumstance in the lease agreement on which those payments are assessed occurs. Variable lease payments, when applicable, are presented as *"Gathering and other"* or *"General and administrative"* in the consolidated statements of operations in the same line item as the expense arising from the fixed lease payments on the operating leases.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

The *"Operating lease right of use assets"* outstanding on the consolidated balance sheet as of December 31, 2023 have initial lease terms of 1.9 years and 2.7 years and the *"Operating lease right of use assets"* as of December 31, 2022 have initial lease terms of 2.3 years. The table below summarizes the Company's leases for the periods indicated (in thousands, except years and discount rate):

	Years Ended December 31,	
	2023	2022
Lease cost		
Operating lease costs	$ 601	$ 391
Short-term lease costs	2,536	7,972
Total lease costs	$ 3,137	$ 8,363
Other information		
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 604	$ 391
Weighted-average remaining lease term - operating leases	1.8 years	0.9 years
Weighted-average discount rate - operating leases	12.32 %	4.29 %

Future minimum lease payments associated with the Company's non-cancellable operating leases for office space and equipment as of December 31, 2023, are presented in the table below (in thousands):

	December 31, 2023
2024	$ 688
2025	430
2026	86
Total operating lease payments	1,204
Less: discount to present value	(120)
Total operating lease liabilities	1,084
Less: current operating lease liabilities	594
Noncurrent operating lease liabilities	$ 490

4. OPERATING REVENUES

Substantially all of the Company's oil, natural gas, and NGL revenues are derived from the Delaware Basin in Pecos, Reeves, Ward and Winkler Counties, Texas. Revenue is presented disaggregated in the statement of operations by major product, and depicts how the nature, timing, and uncertainty of revenue and cash flows are affected by economic factors in the Company's single basin operations.

Revenue is recognized when the following five steps are completed: (1) identify the contract with the customer, (2) identify the performance obligation (promise) in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, (5) recognize revenue when the reporting organization satisfies a performance obligation. Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized, at a point in time, when a performance obligation is satisfied by the transfer of control of each unit (e.g. barrel of oil, Mcf of gas) of commodity to the customer. Revenue is measured based on contract consideration allocated to each unit of commodity and excludes amounts collected on behalf of third parties. Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction that are collected by the Company from a customer are excluded from revenue.

Since the Company's performance obligations have been satisfied and an unconditional right to consideration exists as of the balance sheet date, the Company recognized amounts due from contracts with customers of $ 19.8 million and $ 34.0 million as of December 31, 2023 and 2022, respectively, as *"Accounts receivable, net"* on the consolidated balance sheets. The Company utilizes the practical expedient exempting the disclosure of the transaction price of unsatisfied performance obligations for (i) contracts with an original expected duration of one year or less and (ii) contracts where variable consideration is allocated entirely to a wholly unsatisfied performance obligation (each unit of product typically represents a separate performance obligation, and therefore, future volumes under the Company's long-term contracts are wholly unsatisfied).

The Company records revenue in the month its production is delivered to the purchaser. However, to the extent settlement statements and/or payments are not available, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

Oil Sales

The Company recognizes revenue when control of the crude oil transfers at the delivery point at the net price received. Generally, this occurs when the Company (i) sells its crude oil production at the wellhead where control of the crude oil transfers to the customer at an index price, averaged over the daily settlement prices for a production month, and adjusted for pricing differentials and other deduction or (ii) when delivered to the customer at a contractual delivery point at which the customer takes custody, title and risk of loss of the product. The Company receives a specified index price from the customer, averaged over the daily settlement prices for a production month, and net of applicable market-related adjustments. Settlement statements for the Company's crude oil production are typically received within the month following the date of production and therefore the amount of production delivered to the customer and the price that will be received for that production are known at the time the revenue is recorded.

Natural Gas and NGL Sales

The Company evaluates its natural gas gathering and processing arrangements in place with midstream companies to determine when control of the natural gas is transferred. Under contracts where it is determined that control of the natural gas transfers at the wellhead, any fees incurred to gather or process the unprocessed natural gas are treated as a reduction of the sales price of unprocessed natural gas, and therefore revenues from such transactions are presented on a net basis. Under contracts where it is determined that control of the natural gas transfers at the tailgate of the midstream entity's processing plant, revenues are presented on a gross basis for amounts expected to be received from the midstream company or third party purchasers through the gathering and treating process and presented as *"Natural gas"* or *"Natural gas liquids"* and any fees incurred to gather or process the natural gas are presented separately as *"Gathering and other"* on the consolidated statements of operations.

Under certain contracts, the Company may elect to take its residue gas and/or natural gas liquids in-kind at the tailgate of the midstream entity's processing plant. The Company then sells the products to a customer at contractual delivery points at prices based on an index. In these instances, revenues are presented on a gross basis and any fees incurred to gather, process or transport the commodities are presented separately as "*Gathering and other*" on the consolidated statements of operations.

The majority of the Company's natural gas and NGLs prices are based on daily average pricing for the month. Settlement statements for the Company's natural gas and NGLs production are typically received 30 days after the date of production and therefore the Company estimates the amount of production delivered to the customer and the price that will be received for that production. Historically, differences between the Company's estimates and the actual revenue received have not been material.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

5. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2023 and 2022 consisted of the following (in thousands):

	December 31, 2023	December 31, 2022
Subject to depletion	$ 755,482	$ 713,585
Not subject to depletion:		
Other capital costs:		
Incurred in 2023	31	—
Incurred in 2022	1,427	1,427
Incurred in 2021 and prior (1)	57,451	61,194
Total not subject to depletion	58,909	62,621
Gross oil and natural gas properties	814,391	776,206
Less accumulated depletion	(445,975)	(390,796)
Net oil and natural gas properties	$ 368,416	$ 385,410

(1) In 2019, with the adoption of fresh-start accounting, the Company's unevaluated properties were recorded at fair value.

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, treating equipment and gathering support facilities costs, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. Depletion expense was $ 55.2 million and $ 51.0 million for the year ended December 31, 2023 and 2022, respectively. Depletion expense is recorded in *"Depletion, depreciation and accretion"* in the Company's consolidated statements of operations.

The net capitalized costs of evaluated oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10 %, net of tax considerations. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs are charged to expense.

The ceiling test value of the Company's reserves was calculated based on the following prices:

	West Texas Intermediate (per barrel) (1)	Henry Hub (per MMBtu) (1)
December 31, 2023	$ 78.21	$ 2.64
December 31, 2022	94.14	$ 6.36

(1) Unweighted average of the first day of the 12-months ended spot price, adjusted by lease or field for quality, transportation fees, and regional price differentials.

The Company's net book value of oil and natural gas properties for both 2023 and 2022 did not exceed the ceiling amount. Changes in commodity prices, production rates, levels of reserves, future development costs, transfers of unevaluated properties to the full cost pool, capital spending, and other factors will determine the Company's ceiling test calculation and impairment analyses in future periods.

6. DEBT

As of December 31, 2023 and 2022, the Company's debt consisted of the following (in thousands):

	December 31, 2023	December 31, 2022
Term loan credit facility	$ 200,000	$ 235,000
Other	215	190
Total debt (Face Value)	200,215	235,190
Less:		
Current Portion of Long-Term Debt[1]	(50,106)	(35,067)
Other[2]	(9,833)	(17,447)
Long-Term Debt, net	$ 140,276	$ 182,676

(1) *Amounts primarily reflect payments due of $ 50.0 million and $ 35.0 million under the Amended Term Loan Agreement due within one year as of December 31, 2023 and December 31, 2022, respectively.*

(2) *Amounts primarily reflect unamortized debt issuance costs of approximately $ 6.9 million and $ 13.0 million at December 31, 2023 and December 31, 2022, respectively, but also include an unamortized debt discount associated with an embedded derivative separately presented and further described in Note 7. "Fair Value Measurements". For the years ended December 31, 2023 and 2022, we recorded approximately $ 7.6 million and $ 5.4 million, respectively, in interest expense reflecting the amortization/accretion of these amounts.*

Term Loan Credit Facility

On November 24, 2021, the Company and its wholly owned subsidiary, Halcón Holdings, LLC (Borrower) entered into an Amended and Restated Senior Secured Credit Agreement (Term Loan Agreement) with Macquarie Bank Limited, as administrative agent, and certain other financial institutions party thereto, as lenders. The Term Loan Agreement amended and restated in its entirety the senior secured revolving credit agreement, as amended, (the Senior Credit Agreement) entered into in 2019.

On November 14, 2022, the Company paid approximately $ 2.4 million and entered into a further Amended Credit Agreement (the "Amended Term Loan Agreement") with its lenders which modified certain provisions of its original Term Loan Agreement. The Amended Term Loan Agreement also contains certain financial covenants (as defined in the Amended Term Loan Agreement), including the maintenance of the following ratios:

- Asset Coverage Ratio of not less than 1.80 to 1.00 as of December 31, 2023 and the last day of each fiscal quarter thereafter;
- Total Net Leverage Ratio of not greater than 2.50 to 1.00 as of December 31, 2023 and each fiscal quarter thereafter, and
- Current Ratio of not less than 1.00 to 1.00, determined as of the last day of any fiscal quarter period, as of December 31, 2023 and each fiscal quarter thereafter.

As of December 31, 2023, the Company was in compliance with the financial covenants under the Amended Term Loan Agreement.

The Company may elect, at its option, to prepay any borrowings outstanding under the Amended Term Loan Agreement subject to the following prepayment premiums:

Period (after applicable borrowing date (1))	Premium	
Months 0 - 12	Make-whole amount equal to 12 months of interest plus	2.00 %
Months 13 - 24		2.00 %
Months 25 - 36		1.00 %
Months 37 - 48		0.00 %

(1) *Applicable borrowing dates are November 2021 for the original $ 200.0 million borrowed and April and November 2022 for the $ 20.0 million and $ 15.0 million in delayed borrowings, respectively.*

The Company's prepayment premiums would differ from those noted in the table above if a change of control results in prepayment within the second anniversary of the amendment date, as a 2 % payment premium will apply.

As of December 31, 2023, the Company had $ 200.0 million of indebtedness outstanding and approximately $ 0.3 million of letters of credit outstanding under the Amended Term Loan Agreement. An additional $ 4.7 million is available for the issuance of letters of credit. The Company has a variable interest rate on its borrowings based on SOFR plus an applicable margin of 7.5 %. The weighted average interest rate on the Company's borrowings for the year ended December 31, 2023 was approximately 12.68 %. The maturity date of the Amended Term Loan Agreement is November 24, 2025 .

The Company may be required to make mandatory prepayments under the Amended Term Loan Agreement in connection with the incurrence of non-permitted debt, certain asset sales, or with excess cash on hand in excess of certain maximum levels beginning in 2023. For each fiscal quarter after January 1, 2023, the Company is required to make mandatory prepayments when the Consolidated Cash Balance, as defined in the Amended Term Loan Agreement, exceeds $ 20.0 million. Until December 31, 2024, the forecasted capital expenditures for the succeeding fiscal quarter on the approved plan of development ("APOD") wells (i.e. oil and natural gas wells located within a specified boundary as set by the Amended Term Loan Agreement) are excluded for purposes of determining the Consolidated Cash Balance. As of December 31, 2023, the Consolidated Cash Balance, as defined in the Amended Term Loan Agreement, did not exceed $ 20.0 million when considering forecasted APOD capital expenditures and cash held in unrestricted subsidiaries; therefore, no mandatory prepayment was necessary.

The Company is required to make scheduled remaining amortization payments in the aggregate amount of $ 85.0 million from the fiscal quarter ending March 31, 2024 through the fiscal quarter ending September 30, 2025 with $ 10.0 million due at the end of the first quarter of 2024, $ 12.5 million due at the end of each of the second and third quarters of 2024, $ 15.0 million due at the end of the fourth quarter of 2024 and the first quarter of 2025, and $ 10.0 million due at the end of each of the second and third quarters of 2025. The Company will be required to make a final payment of $ 115.0 million at maturity on November 24, 2025. Amounts outstanding under the Amended Term Loan Agreement are guaranteed by certain of the Borrower's direct and indirect subsidiaries and secured by substantially all of the assets of the Borrower and such direct and indirect subsidiaries, and by the equity interests of the Borrower held by the Company. As part of the Amended Term Loan Agreement there are certain restrictions on the transfer of assets, including cash, to Battalion from the guarantor subsidiaries.

The Amended Term Loan Agreement also contains an APOD for the Company's Monument Draw acreage through the drilling and completion of certain wells. The Amended Term Loan Agreement contains a proved developed producing production test and an APOD economic test which the Company must maintain compliance with; otherwise, subject to any available remedies or waivers, the Company is required to immediately cease making expenditures in respect of the APOD other than any expenditures deemed necessary by the Company in respect of no more than six additional APOD wells.

The Amended Term Loan Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; judgments; change of control; and voluntary and involuntary bankruptcy.

In conjunction with entering into the original Term Loan Agreement in November 2021, the Company agreed to pay a premium to the lenders upon a future change of control event in which a majority of the board of directors or the Chief Executive Officer (the “CEO”) or the Principal Chief Financial Officer positions do not remain held by the same persons as before the change of control event (“Change of Control Call Option”). The premium is reduced over time through the payment of interest and certain fees. The Change of Control Call Option is accounted for as an embedded derivative not clearly and closely related to the host debt instrument. Accordingly, the Company recorded the initial fair value separately on the consolidated balance sheet within *“Other noncurrent liabilities”* and records changes in the fair value of the embedded derivative each reporting period in *“Interest expense and other”* on the consolidated statements of operations. Refer to Note 7, “*Fair Value Measurements*,” for a discussion of the valuation approach used, the significant inputs to the valuation, and for a reconciliation of the change in fair value of the Change of Control Call Option.

Debt Maturities

Aggregate maturities required on debt at December 31, 2023 due in future years are as follows (in thousands):

2024	$ 50,106
2025	150,096
2026	13
Total	$ 200,215

7. FAIR VALUE MEASUREMENTS

The Company’s determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company’s consolidated balance sheets, but also the impact of the Company’s nonperformance risk on its own liabilities. Fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company separates the fair value of its financial instruments using a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

A financial instrument’s level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for any period presented. The following tables set forth by level within the fair value hierarchy the Company’s financial assets and liabilities associated with commodity-based derivative contracts that were accounted for at fair value as of December 31, 2023 and 2022 (in thousands):

	December 31, 2023			
	Level 1	Level 2	Level 3	Total
Assets				
Assets from commodity-based derivative contracts	$ —	$ 13,869	$ —	$ 13,869
Liabilities				
Liabilities from commodity-based derivative contracts	$ —	$ 33,249	$ —	$ 33,249

	December 31, 2022			
	Level 1	Level 2	Level 3	Total
Assets				
Assets from commodity-based derivative contracts	$ —	$ 21,623	$ —	$ 21,623
Liabilities				
Liabilities from commodity-based derivative contracts	$ —	$ 62,935	$ —	$ 62,935

Derivative contracts listed above as Level 2 include fixed-price swaps, collars, puts, calls, basis swaps and WTI NYMEX rolls that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's consolidated statements of operations. The Level 2 observable data includes the forward curves for commodity prices based on quoted market prices and implied volatility factors related to changes in the forward curves. See Note 8, *"Derivative and Hedging Activities,"* for additional discussion of derivatives.

The Company's derivative contracts are with major financial institutions with investment grade credit ratings which are believed to have minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts; however, the Company does not anticipate such nonperformance.

As discussed in Note 6, *"Debt,"* the Company recorded the fair value of the Change of Control Call Option separately on the consolidated balance sheets in *"Other noncurrent liabilities."* The fair value of the Change of Control Call Option is subsequently remeasured each reporting period with fair values changes recorded in "*Interest expense and other"* on the consolidated statement of operations. The valuation of the Change of Control Call Option includes significant inputs such as the timing and probability of discrete potential exit scenarios, forward interest rate curves, and discount rates based on implied and market yields. The following table sets forth a reconciliation of the changes in fair value of the Change of Control Call Option classified as Level 3 in the fair value hierarchy (in thousands):

	Change of Control Call Option
Balance at December 31, 2022	$ 4,136
Change in fair value	(2,052)
Balance at December 31, 2023	$ 2,084

Estimated fair value amounts have been determined at discrete points in time based on relevant market information. The estimated fair value of cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of borrowings under the Company's Amended Term Loan Agreement approximate carrying value because the interest rates approximate current market rates.

The Company follows the provisions of the FASB's ASC Topic 820, *Fair Value Measurement* for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. These provisions apply to the Company's initial recognition of AROs for which fair value is used. The ARO estimates are derived from historical costs and management's expectation of future cost environments; and therefore, the Company has designated these liabilities as Level 3. See Note 8, *"Asset Retirement Obligations,"* for a reconciliation of the beginning and ending balances of the liability for the Company's AROs.

8. DERIVATIVE AND HEDGING ACTIVITIES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. In accordance with the Company's policy and the requirements under the Term Loan Agreement, it generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *"Net gain (loss) on derivative contracts"* on the consolidated statements of operations. The Company's hedge policies and objectives may change significantly as its operational profile changes. The Company does not enter into derivative contracts for speculative trading purposes.

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial or commodity hedging institutions deemed by management as competent and competitive market makers. As of December 31, 2023, the Company did not post collateral under any of its derivative contracts as they are secured under the Company's Amended Term Loan Agreement.

The Company's crude oil and natural gas derivative positions at any point in time may consist of fixed-price swaps, costless put/call collars, basis swaps and WTI NYMEX rolls further described as follows:

- *Fixed-price swaps* are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas.

- *Costless collars* consist of a sold call, which establishes a maximum price the Company will receive for the volumes under contract and a purchased put that establishes a minimum price and are generally utilized less frequently by the Company than fixed-price swaps.

- *Basis swaps* effectively lock in a price differential between regional prices (i.e. Midland) where the product is sold and the relevant pricing index under which the oil production is hedged (i.e. Cushing).

- *WTI NYMEX roll agreements* account for pricing adjustments to the trade month versus the delivery month for contract pricing.

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of December 31, 2023 and 2022 (in thousands):

Balance sheet location	Years Ended December 31, 2023	Years Ended December 31, 2022	Balance sheet location	Years Ended December 31, 2023	Years Ended December 31, 2022
Current assets	$ 8,992	$ 16,244	Current liabilities	$ (17,191)	$ (29,286)
Other noncurrent assets	4,877	5,379	Other noncurrent liabilities	(16,058)	(33,649)
	$ 13,869	$ 21,623		$ (33,249)	$ (62,935)

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations (in thousands):

Type	Location of gain or (loss) on derivative contracts on Statement of Operations	Years Ended December 31, 2023	Years Ended December 31, 2022
Commodity contracts:			
Unrealized gain (loss)	Other income (expenses)	$ 21,934	$ 20,256
Realized gain (loss)	Other income (expenses)	(9,245)	(130,262)
Total net gain (loss)		$ 12,689	$ (110,006)

At December 31, 2023, the Company had the following open crude oil and natural gas derivative contracts:

Instrument	2024	2025	2026	2027
Crude oil:				
Fixed-price swap:				
Total volumes (Bbls)	1,834,924	1,405,463	1,016,641	620,387
Weighted average price	$ 63.62	$ 61.59	$ 63.50	$ 61.38
Basis swap:				
Total volumes (Bbls)	1,834,321	1,430,806	1,023,669	682,265
Weighted average price	$ 0.27	$ 0.24	$ 0.04	$ 0.44
WTI NYMEX roll:				
Total volumes (Bbls)	1,814,073	1,430,806	1,023,669	682,265
Weighted average price	$ 0.27	$ 0.13	$ (0.01)	$ (0.02)
Natural gas:				
Fixed-price swap:				
Total volumes (MMBtu)	4,452,855	4,284,179	2,357,998	1,587,636
Weighted average price	$ 3.54	$ 3.40	$ 3.96	$ 3.68
Two-way collar:				
Total volumes (MMBtu)	2,610,639	1,651,321	2,063,812	1,355,000
Weighted average price (call)	$ 5.08	$ 5.12	$ 5.26	$ 5.57
Weighted average price (put)	$ 3.67	$ 3.72	$ 3.70	$ 3.66
Basis swap:				
Total volumes (MMBtu)	7,052,822	5,834,257	4,382,626	2,653,497
Weighted average price	$ (0.87)	$ (0.68)	$ (0.77)	$ (0.71)

The Company presents the fair value of its derivative contracts at the gross amounts in the consolidated balance sheets. The following table shows the potential effects of master netting arrangements on the fair value of the Company's derivative contracts at December 31, 2023 and 2022 (in thousands):

Offsetting of Derivative Assets and Liabilities	Derivative Assets Years Ended December 31, 2023	Derivative Assets Years Ended December 31, 2022	Derivative Liabilities Years Ended December 31, 2023	Derivative Liabilities Years Ended December 31, 2022
Gross Amounts - Consolidated Balance Sheet	$ 13,869	$ 21,623	$ (33,249)	$ (62,935)
Amounts Not Offset - Consolidated Balance Sheet	(13,218)	(20,997)	13,218	20,997
Net amount	$ 651	$ 626	$ (20,031)	$ (41,938)

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

The Company enters into an International Swap Dealers Association Master Agreement (ISDA) with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

9. ASSET RETIREMENT OBLIGATIONS

The Company records an ARO on oil and natural gas properties when it can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. The Company records AROs to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells, treating equipment and gathering support facilities.

The Company recorded the following activity related to its ARO liability (inclusive of the current portion) (in thousands):

	For the Year Ended December 31,	
	2023	2022
Asset retirement obligations at beginning of the period	$ 15,469	$ 11,896
Accretion expense	793	528
Liabilities incurred	34	151
Liabilities settled/divested	(112)	(647)
Revisions to estimate	1,274	3,541
Asset retirement obligations at end of period	17,458	15,469
Less: current asset retirement obligations	—	(225)
Long-term asset retirement obligations at the end of the period	$ 17,458	$ 15,244

10. COMMITMENTS AND CONTINGENCIES

Commitments

As of December 31, 2023, the Company has an active drilling rig commitment of approximately $ 1.5 million that will be incurred in 2024. Termination of the active drilling rig commitment would require an early termination penalty of $ 1.3 million, which would be in lieu of paying the active drilling rig commitment of $ 1.5 million.

In May 2022, the Company entered into a joint venture agreement to develop a strategic acid gas treatment and carbon sequestration facility and entered into a gas treating agreement. Once the facility is in service, the Company has a minimum volume commitment of 20,000 Mcf per day under the gas treating agreement, with certain rollover rights and start-up flexibility, for an initial term of five years from the in-service date of the facility. Under the gas treating agreement, the Company will pay a treating rate that begins at $ 1.65 /Mcf and varies based on volumes delivered to the facility. At an initial treated volume of 12,000 Mcf/d, the commitment would be approximately $ 7.3 million for the first 12 months of the agreement. For additional information on this joint venture, see Note 15, *Additional Financial Information*.

The Company has entered into various long-term gathering, transportation and sales contracts with respect to its oil and natural gas production from the Delaware Basin in West Texas. As of December 31, 2023, the Company had in place multiple long-term crude oil and natural gas contracts in this area and the sales prices under these contracts are based on posted market rates. Under the terms of these contracts, the Company has committed a substantial portion of its production from this area for periods ranging from one to twenty years from the date of first production.

Contingencies

In addition to the matters described below, from time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. While the outcome and impact of currently pending legal proceedings cannot be determined, the Company's management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on the Company's consolidated operating results, financial position or cash flows.

Surface owners of properties in Louisiana, where the Company formerly operated, often file lawsuits or assert claims against oil and gas companies claiming that operators and working interest owners are liable for environmental damages arising from operations conducted on the leased properties. These damages are frequently measured by the cost to restore the leased properties to their original condition. Currently and in the past, the Company has been party to such matters in Louisiana. With regard to pending matters, the overall exposure is not currently determinable. The Company intends to vigorously oppose these claims.

11. REDEEMABLE CONVERTIBLE PREFERRED STOCK

On March 28, 2023, the Company sold, in a private placement, an aggregate of 25,000 shares of Series A Redeemable Convertible Preferred Stock (the "Series A Preferred Stock") to certain funds managed by Luminus Management, LLC, Oaktree Capital Management, LP, and LSP Investment Advisors, LLC, the Company's largest three existing stockholders (collectively, the "Investors") that represent 50 percent of its board of directors. The Company received $ 24.4 million in proceeds, net of $ 0.6 million in original issue discount. The issuance of Series A Preferred Stock was approved by the Company's board of directors upon recommendation by a special committee of disinterested directors that was established to evaluate the proposed terms of the Series A Preferred Stock. Holders of Series A Preferred Stock will have no voting rights with respect to the shares of Series A Preferred Stock. The Series A Preferred Stock will receive annual dividends, paid either in cash at a fixed rate of 14.5 % annually or accrued at a fixed rate of 16.0 % annually ("PIK accrual") at the option of the Company. Currently, the Company's Amended Term Loan Agreement prohibits the payment of cash dividends. Paid-in-kind ("PIK") dividends will be cumulative, compound and accrue quarterly in arrears and will be added to the Liquidation Preference. The Series A Preferred Stock Dividend Payment Date commenced on June 30, 2023, and the Conversion Price equaled $ 9.03 , which may be adjusted from time to time.

On September 6, 2023, the Company sold, in a private placement, an aggregate of 38,000 shares of Series A-1 Redeemable Convertible Preferred Stock (the "Series A-1 Preferred Stock") to the Investors. The Company received $ 37.1 million in proceeds, net of $ 0.9 million in original issue discount. The issuance of Series A-1 Preferred Stock was approved by the Company's board of directors upon recommendation by a special committee of disinterested directors that was established to evaluate the proposed terms of the Series A-1 Preferred Stock. Holders of Series A-1 Preferred Stock will have no voting rights with respect to the shares of Series A-1 Preferred Stock. The Series A-1 Preferred Stock will receive annual dividends, paid either in cash at a fixed rate of 14.5 % annually or accrued at a fixed PIK accrual rate of 16.0 % annually at the option of the Company. Currently, the Company's Amended Term Loan Agreement prohibits the payment of cash dividends. PIK dividends will be cumulative, compound and accrue quarterly in arrears and will be added to the Liquidation Preference. The Series A-1 Preferred Stock Dividend Payment Date commenced on September 30, 2023, and the Conversion Price equaled $ 7.63 , which may be adjusted from time to time.

On December 15, 2023, the Company sold, in a private placement, an aggregate of 35,000 shares of Series A-2 Redeemable Convertible Preferred Stock (the "Series A-2 Preferred Stock") to the Investors. The Company received $ 34.1 million in proceeds, net of $ 0.9 million in original issue discount. The issuance of Series A-2 Preferred Stock was approved by the Company's board of directors upon recommendation by a special committee of disinterested directors that was established to evaluate the proposed terms of the Series A-2 Preferred Stock. Holders of Series A-2 Preferred Stock will have no voting rights with respect to the shares of Series A-2 Preferred Stock. The Series A-2 Preferred Stock will receive annual dividends, paid either in cash at a fixed rate of 14.5 % annually or accrued at a fixed PIK accrual rate of 16.0 % annually at the option of the Company. Currently, the Company's Amended Term Loan Agreement prohibits the payment of cash dividends. PIK dividends will be cumulative, compound and accrue quarterly in arrears and will be added to the Liquidation Preference. The Series A-2 Preferred Stock Dividend Payment Date commenced on December 31, 2023, and the Conversion Price equaled $ 6.21 , which may be adjusted from time to time.

For accounting purposes, upon issuance of the preferred stock on March 28, 2023, September 6, 2023 and December 15, 2023 (collectively, the "Redeemable Convertible Preferred Stock"), the Company recorded $ 23.5 million ($ 25.0 million net of original issue discount and accrued offering costs), $ 36.9 million ($ 38.0 million net of original issue discount and accrued offering costs) and $ 34.0 million ($ 35.0 million net of original issue discount and accrued offering costs), respectively, as mezzanine equity (temporary equity) on the consolidated balance sheets because it is not mandatorily redeemable but does contain a redemption feature at the option of the preferred holders that is considered not solely within the Company's control. Due to the redeemable nature of the preferred stock, as further discussed below, at March 31, 2023, September 30, 2023 and December 31, 2023, the Company recorded non-cash deemed dividends of approximately $ 1.5 million, $ 1.1 million and $ 1.0 million, respectively, to increase the carrying value of the preferred stock to its redemption amounts of approximately $ 25.0 million, $ 38.0 million and $ 35.0 million, respectively.

For year ended December 31, 2023, the Company paid-in-kind its dividend on the preferred stock of $ 8.5 million. As of December 31, 2023, the carrying value of the preferred stock, inclusive of PIK dividends, is approximately $ 106.5 million.

Voting Rights. Holders of shares of the Redeemable Convertible Preferred Stock have no voting rights with respect to the shares of Redeemable Convertible Preferred Stock.

Dividends. Holders of Redeemable Convertible Preferred Stock are entitled to receive cumulative dividends at a fixed rate of 14.5 % per annum on the Liquidation Preference ($ 1,000 per share, or $ 98.0 million, increased for any PIK accruals), compounding and accruing quarterly in arrears. Dividends may be paid in cash or, if not declared and paid in cash, the amount of any such dividend shall automatically accrue at a fixed rate of 16.0 % per annum on the Liquidation Preference and be added to the Liquidation Preference (a "PIK Accrual"). Currently, the Company's Amended Term Loan Agreement prohibits the payment of cash dividends. Additionally, while the Company has not declared or paid dividends on its common stock since its inception, holders of preferred stock will be entitled to participate in any dividends or permitted distributions to holders of common stock on an as-converted basis should they occur.

Conversion Features. In addition to the conversion rights noted in " *Redemption Features (Change of Control)* " below, holders of Redeemable Convertible Preferred Stock may convert their shares into common stock at the Conversion Ratio equal to the then applicable Liquidation Preference at the time of conversion divided by the then applicable Conversion Price (initially equal to an 18 % premium to the volume weighted average price of common stock for the 20 trading days immediately preceding the closing date). Additionally, the Company has the right, at its option, to convert outstanding shares of Redeemable Convertible Preferred Stock into common stock at the Conversion Ratio should the Company meet certain calculated valuation metrics which when divided by the number of outstanding shares of common stock equals or exceeds 130 % of the Conversion Price.

Redemption Features (Issuer). The Company has the option to redeem the preferred stock in cash for an amount per share of Preferred Stock equal to (the "Redemption Price"):

- at any time prior to 120 days following the closing date, 100 % of the Liquidation Preference at such time;
- at any time on or after 120 days following the closing date but prior to the 180 days following the closing date, 102 % of the Liquidation Preference at such time;
- at any time on or after 180 days following the closing date but on or prior to the first anniversary of the closing date, 105 % of the Liquidation Preference at such time;

- at any time after the first anniversary of the closing date but on or prior to the second anniversary of the closing date, 108 % of the Liquidation Preference at such time; and
- at any time after the second anniversary of the closing date, 120 % of the Liquidation Preference at such time.

Redemption Features (Change of Control). In the event of a change of control, holders have the right to receive:

- at any time on or prior to 150 days following the issuance date, and at the election of the Company, a cash payment equal to the Liquidation Preference or equity consideration equal to the 107.5 % of the Liquidation Preference, or
- at any time after the one hundred fiftieth (150 th) day following the issuance date, the Company shall offer each Holder a cash payment equal to the Redemption Price. Holders shall also have the ability to elect conversion into common stock at the Conversion Ratio. Until (i) a termination of or certain amendments to the Amended Term Loan Agreement or (ii) one year past the maturity date of the Amended Term Loan Agreement, an election of the cash payment option by holders in a change of control scenario is not permitted.

12. STOCKHOLDERS' EQUITY

Common Stock

On October 8, 2019, upon emergence from chapter 11 bankruptcy, Battalion filed an amended and restated certificate of incorporation with the Delaware Secretary of State to provide for, among other things, (i) the total number of shares of all classes of capital stock that Battalion has the authority to issue is 101,000,000 of which 100,000,000 shares are common stock, par value $ 0.0001 per share and 1,000,000 shares are preferred stock, par value $ 0.0001 per share and (ii) a restriction on Battalion from issuing any non-voting equity securities in violation of Section 1123(a)(6) of chapter 11 of title 11 of the United States Code. In addition, pursuant to the Company's certificate of incorporation, effective at the 2021 annual meeting of stockholders, the board ceased to be divided into two classes, and the provision for the right of removal of any directors designated as a Group II director by an increased voting threshold from a majority to 85 % of the shares then entitled to vote at an election of directors shares expired.

Incentive Plans

The Company's board of directors adopted the 2020 Long-Term Incentive Plan (the "Plan"), as amended in 2021, in which an aggregate of approximately 1.8 million shares of the Company's common stock were available for grant pursuant to awards under the Plan. As of December 31, 2023, a maximum of 1.1 million shares of the Company's common stock remained reserved for issuance under the Plan. For the years ended December 31, 2023 and 2022, the Company recognized a benefit of $ 1.1 million and expense of $ 2.2 million, respectively, related to stock-based compensation awards granted to employees and directors, primarily related to restricted stock unit grants. The benefit recognized in the twelve months ended December 31, 2023 is due to forfeitures of stock options and restricted stock related to the departure of certain executives and employees. Stock-based compensation is recorded as a component of *"General and administrative"* on the consolidated statements of operations.

Restricted Stock Units

From time to time, the Company grants shares of restricted stock units ("RSUs") under the Plan to employees of the Company. Under the Plan, employee RSUs will vest and convert to shares typically in equal amounts over a three or four year vesting period from the date of the grant, depending on award, or when the performance or market conditions described below occur. At December 31, 2023 and 2022, the Company had $ 0.3 million and $ 2.6 million, respectively of unrecognized compensation expense related to non-vested RSU awards to be recognized over a weighted average period of 0.3 years and 1 year, respectively.

The following table sets forth the restricted stock unit transactions for the periods indicated:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value[(1)] (In thousands)
Unvested outstanding shares at December 31, 2021	775,515	$ 9.16	$ 2,914
Granted	225,700	13.75	
Vested	(98,121)	11.40	
Forfeited	(13,700)	12.20	
Unvested outstanding shares at December 31, 2022	889,394	$ 10.03	$ 3,993
Granted	30,000	10.68	
Vested	(158,845)	12.48	
Forfeited	(509,013)	9.04	
Unvested outstanding shares at December 31, 2023	251,536	$ 10.56	$ 1,141

(1) *The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2023 and 2022 of the underlying stock multiplied by the number of restricted shares that would be issuable. The total fair value of shares vested was $ 1.5 million for the year ended December 31, 2023.*

The discussion below outlines the vesting conditions and fair values for each type of the Company's approximately 0.3 million unvested outstanding RSU under the Plan issued to employees of the Company as of December 31, 2023.

- *Time-Based RSUs*. 0.1 million Time-Based RSUs will vest over a three or four year vesting period from the date of the grant, depending on award. The aggregate grant date fair value of these RSUs was $ 1.6 million.

- *Performance-Based RSUs*. Less than 0.1 million Performance-Based RSUs will vest in full only upon achievement of certain business combination goals, as defined in the awards agreements. The aggregate grant date fair value of these RSUs was $ 0.5 million. As of December 31, 2023, no expense had been recognized for these awards as a business combination, as defined in the award agreements, had not been consummated.

- *Market-Based (e.g. TSR) RSUs*. 0.1 million Market-Based RSUs will vest in full or in part or may terminate based on the Company's total shareholder return ("TSR") relative to the total shareholder return of certain of its peer companies as defined in the awards agreements over the performance period ending on February 20, 2024. The aggregate grant date fair value of these RSUs was $ 0.6 million.

The assumptions used in calculating the Monte Carlo valuation model fair value of the Company's RSUs with market based (e.g. TSR) vesting conditions granted in 2020 are set forth in the following table:

	Year Ended December 31, 2020
Weighted average value per performance based RSUs granted during the period	$ 6.13
Assumptions:	
Stock price volatility[(1)]	51.79 %
Risk free rate of return	1.22 %

Expected term	3.9 years

(1) *Due to the Company's limited historical data, expected volatility was estimated using volatilities of peer entities as defined in the award agreements whose share prices and assumptions were publicly available.*

Stock Options

From time to time, the Company has granted stock options under the Plan covering shares of common stock to employees of the Company. The Company has not granted stock options since 2020. Stock options, if exercised, are settled through the payment of the exercise price in exchange for new shares of stock underlying the option. Awards granted under the Plan typically vest over a four-year period at a rate of one-fourth on the annual anniversary date of the grant and expire seven years from the date of grant.

At December 31, 2023, the Company had 132,822 options outstanding (three equal tranches of 44,274 options at exercise prices of $ 18.91 , $ 28.23 , and $ 37.83 per share) with a weighted average exercise price of $ 28.32 /share. As of December 31, 2023 and 2022, no options were either exercisable nor had intrinsic value due to service performance conditions and/or based on the exercise price of the option exceeding the closing market price. The weighted average remaining contractual life at December 31, 2023 was approximately 3.1 years. Approximately less than $ 0.1 million of unrecognized compensation expense remains related to non-vested stock-options to be recognized over a weighted-average period of 0.1 years.

The assumptions used in calculating the Black-Scholes-Merton valuation model fair value of the Company's stock options granted in 2020 are set forth in the following table:

	Year Ended December 31, 2020
Weighted average value per option granted during the period	$ 3.36
Assumptions:	
Stock price volatility(1)	61.87 %
Risk free rate of return	1.21 %
Expected term	4.75 years

(1) *Due to the Company's limited historical data, expected volatility was estimated using volatilities of similar entities whose share or option prices and assumptions were publicly available.*

Warrants

On October 8, 2019, pursuant to the Company's plan of reorganization, approximately 6.9 million Series A, Series B and Series C warrants were issued to pre-emergence holders of the predecessor Company's common stock with corresponding initial exercise prices ranging from $ 40.17 to $ 60.45 per share, on a pro rata basis. Each series of Warrants issued under the Warrant Agreement had a three-year term, which expired on October 8, 2022 .

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

13. INCOME TAXES

Income tax benefit (provision) for the indicated periods is comprised of the following (in thousands):

	Years Ended December 31,	
	2023	2022
Current:		
Federal	$ —	$ —
State	—	—
	—	—
Deferred:		
Federal	—	—
State	—	—
	—	—
Total income tax benefit (provision)	$ —	$ —

The actual income tax benefit (provision) differs from the expected income tax benefit (provision) as computed by applying the United States federal corporate income tax rate of 21 % for the periods indicated below, as follows (in thousands):

	Years Ended December 31,	
	2023	2022
Expected tax benefit (provision)	$ 640	$ (3,893)
Change in valuation allowance and related items	(15)	6,689
Attribute reduction	—	(2,704)
Permanent adjustments	(2)	(5)
Employee retention credit	—	—
Non-deductible compensation	(95)	(56)
Preferred equity transaction costs	—	—
Merger transaction costs	(541)	—
Other	13	(31)
Total income tax benefit (provision)	$ —	$ —

BATTALION OIL CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

The components of net deferred income tax assets (liabilities) recognized are as follows (in thousands):

	December 31, 2023	December 31, 2022
Deferred noncurrent income tax assets:		
Net operating loss carry-forwards	$ 172,654	$ 151,905
Built in loss adjustment Section 382	693	693
Capital loss carryforward	114,725	114,725
Stock-based compensation expense	1,693	2,334
Asset retirement obligations	3,666	2,558
Book-tax differences in property basis	106,045	129,427
Unrealized hedging transactions	4,070	8,676
Disallowed interest Section 163(j)	20,712	14,905
Embedded derivative liability	437	459
Operating lease liability	228	74
GAAP amortization - discount on MOIC derivative	—	—
Amortization of debt issuance costs	323	—
Other	874	874
Gross deferred noncurrent income tax assets	426,120	426,630
Valuation allowance	(425,019)	(425,005)
Deferred noncurrent income tax assets	$ 1,101	$ 1,625
Deferred noncurrent income tax liabilities:		
Basis difference in debt	$ (615)	$ (885)
Investment in unconsolidated subsidiary	(270)	(580)
Amortization of debt issuance costs	—	(86)
Lease right of use	(216)	(74)
Deferred noncurrent income tax liabilities	$ (1,101)	$ (1,625)
Net noncurrent deferred income tax assets (liabilities)	$ —	$ —

The amount of U.S. consolidated Net Operating Losses (NOLs) available as of December 31, 2023 after attribute reduction is estimated to be approximately $ 1.3 billion, but the amount after attribute reduction and the Section 382 limitation is $ 822.2 million. Of this amount, $ 92.6 million is subject to the 20 year carryforward period and will expire in 2037. The remaining $ 729.5 million may be carried forward indefinitely but is in part subject to a Section 382 limitation.

The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. The Company evaluated possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies in making this assessment. As a result of the Company’s analysis, it was concluded that as of December 31, 2023, a valuation allowance should continue to be applied against the Company’s net deferred tax asset. The Company recorded a valuation allowance as of December 31, 2023 of $ 425.0 million, a decrease of less than $ 0.1 million from December 31, 2022. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized.

ASC 740 prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company has no unrecognized tax benefits for the year ended December 31, 2023 and 2022. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the consolidated statements of operations in *"Interest expense and other"* or consolidated balance sheets as of December 31, 2023 and 2022. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within the next twelve months.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates.

Generally, the Company's income tax years 2019 through 2023 remain open for federal purposes and are subject to examination by Federal tax authorities. The Company's income tax returns are also subject to audit by the tax authorities in Louisiana, Mississippi, North Dakota, Oklahoma, Texas, Pennsylvania, Ohio and certain other state taxing jurisdictions where the Company has, or previously had, operations. In certain jurisdictions the Company operates through more than one legal entity, each of which may have different open years subject to examination. The open years for state purposes can vary from the normal three year statue expiration period for federal purposes.

14. EARNINGS PER SHARE

The following represents the calculation of earnings (loss) per share (in thousands, except per share amounts):

	Years Ended December 31, 2023	Years Ended December 31, 2022
Basic:		
Net (loss) income	$ (3,048)	$ 18,539
Less: Preferred stock dividend	(12,047)	—
Less: Undistributed earnings allocable to preferred stockholders	—	—
Net (loss) income available to common stockholders	$ (15,095)	$ 18,539
Weighted average basic number of common shares outstanding basic	16,441	16,331
Basic net (loss) income per share of common stock	$ (0.92)	$ 1.14
Diluted:		
Net (loss) income available to common stockholders basic	$ (15,095)	$ 18,539
Reallocation of undistributed earnings	—	—
Net (loss) income available to common stockholders diluted	$ (15,095)	$ 18,539
Weighted average basic number of common shares outstanding	16,441	16,331
Common stock equivalent shares representing shares issuable upon:		
Exercise of warrants and stock options	Anti-dilutive	Anti-dilutive
Vesting of restricted stock units	Anti-dilutive	179
Weighted average diluted number of common shares outstanding diluted	16,441	16,510
Diluted net income (loss) per share of common stock	$ (0.92)	$ 1.12

For the year ended December 31, 2023, common stock equivalents, including stock options and certain restricted stock units, totaling 0.5 million weighted-average shares were anti-dilutive and not included in the computation of diluted earnings per share of common stock. For the year ended December 31, 2022, common stock equivalents, including warrants, stock options and restricted stock units, totaling 5.8 million shares were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive due to the Company's net loss in the period. Additionally, the Company also has approximately 0.1 million restricted stock units that vest only upon achievement of certain business combination goals or based on the Company's TSR as further described in Note 12, "*Stockholder's Equity*". On October 8, 2022 approximately 6.9 million warrants expired which previously gave the holder the right to purchase one share of common stock for each warrant.

15. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following (in thousands) for the periods presents:

	December 31, 2023		December 31, 2022	
Accounts receivable, net:				
Oil, natural gas and natural gas liquids revenues	$	19,802	$	33,980
Joint interest accounts		2,138		3,201
Other		1,081		793
	$	23,021	$	37,974
Prepaids and other:				
Prepaids	$	490	$	715
Funds in escrow		345		341
Other		72		75
	$	907	$	1,131
Other assets (Non-current):				
Investment in unconsolidated affiliate	$	1,283	$	1,561
Contract asset		15,062		—
Funds in escrow		552		527
Other		759		739
	$	17,656	$	2,827
Accounts payable and accrued liabilities:				
Trade payables	$	24,915	$	42,919
Accrued oil and natural gas capital costs		15,337		19,911
Revenues and royalties payable		18,986		26,759
Accrued interest expense		347		160
Accrued employee compensation		520		2,300
Accrued lease operating expenses		6,418		8,005
Other		2		41
	$	66,525	$	100,095

Investment in Unconsolidated Affiliate. In May 2022, the Company entered into a joint venture with Caracara Services, LLC ("Caracara") to develop an acid gas treatment facility to remove hydrogen sulfide and carbon dioxide from its produced natural gas. Caracara provided the initial capital for the construction of the treatment facility. The Company contributed certain full cost pool assets to the related party joint venture in a non-cash exchange for a retained 5 % equity interest in Wink Amine Treater, LLC ("WAT") (previously Brazos Amine Treater, LLC ("BAT")), an unconsolidated subsidiary. For accounting purposes, since the Company does not control the key activities (e.g. operating and maintaining the facility) which most significantly impact economic performance nor does the Company have the obligation to absorb losses or the right to receive benefits that could potentially be significant, the Company is not the primary beneficiary of WAT. Accordingly, the Company accounts for its investment in WAT (a related party) using the equity method of accounting based on its ability to exercise significant influence, but not control, over the key activities of the joint venture. For more information related to this joint venture, see Note 10, "*Commitments and Contingencies*".

Contract Asset. During 2023, the Company advanced a capital contribution of approximately $ 15.1 million on behalf of its joint venture partner in WAT to fund a workover operation on the AGI well. Pursuant to the terms of the agreement governing the joint venture, the Company has multiple remedies to recover such advance, including (1) declaring such payment a loan, which pursuant to the agreement would have an interest rate of the lessor of 15 % or the maximum rate permitted by law, (2) recoupment from distributions from the joint venture and (3) reallocation of equity of the joint venture based on the relative level of total capital contributions by the parties after taking into account the advance. The Company advanced additional capital contributions on behalf of its joint venture partner during the first quarter of 2024 of approximately $ 3.0 million to fund WAT with the necessary capital required to complete the sidetrack of the AGI well.

16. SUBSEQUENT EVENTS

On March 27, 2024, the Company sold, in a private placement, an aggregate of 20,000 shares of Series A-3 Redeemable Convertible Preferred Stock (the “Series A-3 Preferred Stock”) to the Investors. The Company received $ 19.5 million in proceeds, net of $ 0.5 million in original issue discount. The issuance of Series A-3 Preferred Stock was approved by the Company’s board of directors upon recommendation by a special committee of disinterested directors that was established to evaluate the proposed terms of the Series A-3 Preferred Stock. Holders of Series A-3 Preferred Stock will have no voting rights with respect to the shares of Series A-3 Preferred Stock. The Series A-3 Preferred Stock will receive annual dividends, paid either in cash at a fixed rate of 14.5 % annually or accrued at a fixed PIK accrual rate of 16.0 % annually at the option of the Company. Currently, the Company’s Amended Term Loan Agreement prohibits the payment of cash dividends. PIK dividends will be cumulative, compound and accrue quarterly in arrears and will be added to the Liquidation Preference. The Series A-3 Preferred Stock Dividend Payment Date will commence on March 31, 2024, and the Conversion Price equaled $ 6.83 , which may be adjusted from time to time.

On March 28, 2024, the Company entered into the Third Amendment to the Amended Term Loan Agreement (the “Third Amendment”) with its lenders. The Third Amendment, amended the Amended Term Loan Agreement to, among other things, (a) amend the APOD for certain properties, (b) remove the PDP Production Test and APOD Economic Test (each defined in the Term Loan Agreement), (c) require the Borrower to receive cash proceeds from equity issuances and/or cash contributions in an aggregate amount of not less than $ 38.0 million during the period from Amendment Effective Date through March 31, 2024 (the “Specified Additional Equity Capital”), which such Specified Additional Equity Capital shall be excluded from the calculation of Consolidated Cash Balance (as defined in the Term Loan Agreement), and (d) make amendments to certain other affirmative covenants in connection with the foregoing.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of “proved” and “proved developed” oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

The reserves information in this Annual Report on Form 10-K represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the Company’s proved reserves will decline as reserves are produced.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

The proved reserves estimates reported herein for the years ended December 31, 2023 and 2022 have been independently evaluated by Netherland, Sewell & Associates, Inc. (“NSAI”), our independent reserve engineering firm. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see Item 1. *Business* and the report of NSAI which is included as an Exhibit to this Annual Report on Form 10-K.

The following tables illustrate changes in the Company’s estimated net proved developed and proved undeveloped reserves for the periods indicated. The oil and natural gas liquids prices as of December 31, 2023 and 2022 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate spot price which equates to $78.21 per barrel and $94.14 per barrel, respectively. The natural gas prices as of December 31, 2023 and 2022 are based on the respective 12-month unweighted average of the first of the month prices of the Henry Hub spot price which equates to $2.64 per MMBtu and $6.36 per MMBtu, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and market differentials. All prices are held constant in accordance with SEC guidelines. All proved reserves are located in the United States.

	Total Proved Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
Proved reserves, December 31, 2021	58,732	124,965	16,320	95,880
Extensions and discoveries	2,339	18,714	1,560	7,018
Production	(2,834)	(9,336)	(1,245)	(5,635)
Sale of minerals in place	(32)	(17)	(4)	(39)
Revision of previous estimates (1)	(8,183)	9,358	1,420	(5,204)
Proved reserves, December 31, 2022	50,022	143,684	18,051	92,020
Extensions and discoveries	3	6	1	5
Production	(2,415)	(8,718)	(1,163)	(5,031)
Revision of previous estimates (2)	(12,988)	(23,223)	(2,029)	(18,887)
Proved reserves, December 31, 2023	34,622	111,749	14,860	68,107

	Equivalent (Mboe)		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Proved reserves, December 31, 2021	42,410	53,470	95,880
Extensions and discoveries	2	7,016	7,018
Production	(5,635)	—	(5,635)
Sale of minerals in place	(39)	—	(39)
Transfers	8,314	(8,314)	(0)
Revision of previous estimates (1)	1,250	(6,454)	(5,204)
Proved reserves, December 31, 2022	46,302	45,718	92,020
Extensions and discoveries	5	—	5
Production	(5,031)	—	(5,031)
Transfers	2,434	(2,434)	—
Revision of previous estimates (2)	(3,581)	(15,306)	(18,887)
Proved reserves, December 31, 2023	40,129	27,978	68,107

	Proved Developed Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2023	18,626	71,051	9,661	40,129
December 31, 2022	22,501	81,636	10,195	46,302

	Proved Undeveloped Reserves			
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Equivalent (MBoe)
December 31, 2023	15,996	40,698	5,199	27,978
December 31, 2022	27,521	62,048	7,856	45,718

---

(1) *Downward revisions for 2022 of 6.4 MMBoe were primarily due to increased capital and operating costs.*

(2) *Includes downward revisions of 13.0 MMBoe for the removal of PUDs during 2023 due to decreased activity associated with managing cash flow, servicing debt and financial covenants and ongoing work to recapitalize the business.*

Year Ended December 31, 2023

At December 31, 2023, the Company's proved developed reserves of 40.1 MMBoe decreased approximately 6.2 MMBoe from December 31, 2022 primarily as a result of negative revisions of 3.6 MMBoe and production of 5.0 MMBoe offset by PUD reserve development of 2.4 MMBoe.

At December 31, 2023, the Company's estimated proved undeveloped (PUD) reserves of 27.9 MMBoe decreased approximately 17.7 MMBoe from December 31, 2022 as a result of the transfer of 2.4 MMBoe to proved developed producing reserves and downward revisions of 15.3 MMBoe due primarily to the removal of 13.0 MMBoe of PUDs due to decreased activity associated with managing cash flow, servicing debt and financial covenants, and ongoing work to recapitalize the business coupled with a downward revision of 2.3 MMBoe due to decreased SEC prices. All of the Company's PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2023, approximately $33.0 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs.

Year Ended December 31, 2022

At December 31, 2022, the Company's proved developed reserves of 46.3 MMBoe increased approximately 3.9 MMBoe from December 31, 2021 as a result of PUD reserve development of 8.3 MMBoe and positive revisions of 1.2 MMBoe, offset by production of 5.6 MMBoe.

At December 31, 2022, the Company's estimated PUD reserves of 45.7 MMBoe decreased approximately 7.8 MMBoe from December 31, 2021. The transfer of 8.3 MMBoe to proved developed producing reserves and downward revisions of 6.4 MMBoe due primarily to increased capital and operating costs were offset by additions and extensions of 7.0 MMBoe in the Delaware Basin primarily associated with infill drilling activity. All of the Company's PUD reserves are planned to be developed within five years from the date they were initially recorded. During 2022, approximately $119.8 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs.

For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve extrapolation techniques. For undeveloped locations and wells that lacked sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. PUD locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

Reliable technologies were used to determine areas where PUD locations are more than one offset location away from a producing well. These technologies include seismic data, wire line openhole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic EURs from individual producing wells. The Company relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves. Out of total proved undeveloped reserves of 27.9 MMBoe at December 31, 2023, 12.7 MMBoe were associated with 16 gross PUD locations that were more than one offset location from a producing well.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depletion, depreciation and accretion (in thousands):

	December 31, 2023	December 31, 2022
Evaluated oil and natural gas properties	$ 755,482	$ 713,585
Unevaluated oil and natural gas properties	58,909	62,621
	814,391	776,206
Accumulated depletion	(445,975)	(390,796)
	$ 368,416	$ 385,410

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Years Ended December 31,	
	2023	2022
Property acquisition costs, proved	$ —	$ —
Property acquisition costs, unproved	—	—
Exploration and extension well costs	6,691	7,556
Development costs(1)	32,951	119,814
Total costs	$ 39,642	$ 127,370

(1) Excludes $3.5 million and $15.0 million for the years ended December 31, 2023 and 2022, respectively, of development costs related to the Company's treating equipment and gathering support facilities.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following Standardized Measure of Discounted Future Net Cash Flows (Standardized Measure) has been developed utilizing ASC 932, *Extractive Activities—Oil and Gas* (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- future net revenues may be subject to different rates of income taxation.

At December 31, 2023 and 2022, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor.

The Standardized Measure is as follows:

	Years Ended December 31, 2023	Years Ended December 31, 2022
	(In thousands)	
Future cash inflows	$ 3,126,801	$ 6,095,180
Future production costs	(1,483,090)	(2,267,504)
Future development costs	(420,793)	(669,996)
Future income tax expense	(28,551)	(306,160)
Future net cash flows before 10% discount	1,194,367	2,851,520
10% annual discount for estimated timing of cash flows	(595,886)	(1,389,844)
Standardized measure of discounted future net cash flows	$ 598,481	$ 1,461,676

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the two year period ended December 31, 2023:

	Years Ended December 31, 2023	Years Ended December 31, 2022
	(In thousands)	
Beginning of year	$ 1,461,676	$ 1,075,655
Sale of oil and natural gas produced, net of production costs	(126,031)	(220,023)
Sales of minerals in place	—	(536)
Extensions and discoveries	110	84,296
Changes in income taxes, net	91,805	(106,443)
Changes in prices and costs	(656,316)	611,617
Previously estimated development costs incurred	36,744	73,362
Net changes in future development costs	39,252	(103,349)
Revisions of previous quantities	(368,333)	(28,500)
Accretion of discount	156,824	107,577
Changes in production rates and other	(37,250)	(31,980)
End of year	$ 598,481	$ 1,461,676

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(f) and 15d-15(f), of the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer, of the effectiveness of our disclosure controls and procedures based on the *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013 as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer concluded that our disclosure controls and procedures were effective as of December 31, 2023 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Management has assessed our internal control over financial reporting as of December 31, 2023. The unqualified report of management thereon is included in Item 8. *Consolidated Financial Statements and Supplementary Data* of this Annual Report on Form 10-K and is incorporated by reference herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, during the three months ended December 31, 2023 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2023 Annual Meeting of Stockholders.

The Company's Code of Conduct and Code of Ethics for the Principal Executive Officer and Senior Financial Officers can be found on the Company's website located at *www.battalionoil.com*. Any stockholder may request a printed copy of such materials by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least twelve months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2023 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2023 with respect to compensation plans (including individual compensation arrangements) under which our equity securities are authorized for issuance.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options and Rights(A)(1)	Weighted-Average Exercise Price of Outstanding Options and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(A))
Equity compensation plans approved by security holders.	—	$ —	—
Equity compensation plans not approved by security holders(2)	384,358	28.32	1,067,966
	384,358	$ 28.32	1,067,966

(1) *Consists of 251,536 unvested RSUs and outstanding 132,822 stock options.*
(2) *The formation of the plan was approved by the Bankruptcy Court upon confirmation of our Plan of Reorganization in 2019 and further approved by our board with an effective date of January 1, 2020.*

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2023 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2023 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2024 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements:

The consolidated financial statements of the Company and its subsidiaries and reports of independent registered public accounting firms listed in Section 8 of this Annual Report on Form 10-K are filed as a part of this Annual Report on Form 10-K.

(2) Consolidated Financial Statements Schedules:

All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

2.1	Order of the Bankruptcy Court, dated September 24 2019, confirming the Joint Prepackaged Plan of Reorganization of Halcón Resources Corporation, et al, under Chapter 11 of the Bankruptcy Code, together with such Joint Prepackaged Plan of Reorganization (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed September 26, 2019).
2.2	Agreement and Plan of Merger, dated as of December 14, 2023, by and among the Battalion Oil Corporation, Fury Resources, Inc. and San Jacinto Merger Sub, Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed December 18, 2023).
2.2.1	First Amendment to Agreement and Plan of Merger, dated as of January 24, 2024, by and among Battalion Oil Corporation, Fury Resources, Inc. and San Jacinto Merger Sub, Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed January 24, 2024).
2.2.2	Second Amendment to Agreement and Plan of Merger, dated as of February 6, 2024, by and among Battalion Oil Corporation, Fury Resources, Inc. and San Jacinto Merger Sub, Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed February 6, 2024).
2.2.3	Third Amendment to Agreement and Plan of Merger, dated as of February 16, 2024, by and among Battalion Oil Corporation, Fury Resources, Inc. and San Jacinto Merger Sub, Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed February 16, 2024).
2.3	Limited Guarantee, dated February 6, 2024, by Abraham Mirman in favor of Battalion Oil Corporation (Incorporated by reference to Exhibit 2.2 of our Current Report on Form 8-K filed February 6, 2024).
3.1	Amended and Restated Certificate of Incorporation of Battalion Oil Corporation (*formerly* Halcón Resources Corporation) dated October 8, 2019, as amended by the Certificate of Amendment, dated January 21, 2020 (Incorporated by reference to Exhibit 3.1 of our Annual Report on Form 10-K filed March 25, 2020).
3.1.1	Certificate of Designations of Series A Redeemable Convertible Preferred Stock effective March 24, 2023 (Incorporated by reference to Exhibit 3.1.1 of our Annual Report on Form 10-K filed March 30, 2023).
3.1.2	Certificate of Designations of Series A-1 Redeemable Convertible Preferred Stock effective September 6, 2023 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed September 7, 2023).
3.1.3	Certificate of Amendment to Certificate of Designations of Series A-1 Redeemable Convertible Preferred Stock effective December 15, 2023 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed December 18, 2023).

3.1.4	Certificate of Designations of Series A-2 Redeemable Convertible Preferred Stock effective December 15, 2023 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed December 18, 2023).
3.1.5	Certificate of Designations of Series A-3 Redeemable Convertible Preferred Stock dated effective March 27, 2024 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed March 28, 2024).
3.2	Seventh Amended and Restated Bylaws of Battalion Oil Corporation (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed January 27, 2020).
4.1	Description of Battalion Oil Corporation's securities registered under Section 12 of the Exchange Act. (Incorporated by reference to Exhibit 4.1 of our Annual Report on Form 10-K filed March 25, 2020).
10.1	Amended and Restated Senior Secured Credit Agreement dated as of November 24, 2021, by and among Battalion Oil Corporation, as holdings, Halcón Holdings LLC, as borrower, the subsidiary guarantors party thereto, Macquarie Bank Limited, as administrative agent, and the lenders party thereto (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed November 29, 2021).
10.1.1	Second Amendment to Amended and Restated Senior Secured Credit Agreement dated as of November 14, 2022, by and among Halcón Holdings, LLC, as borrower, Macquarie Bank Limited, as administrative agent and the lenders party hereto, the guarantors party hereto and Battalion Oil Corporation, as holdings (Incorporated by reference to Exhibit 10.1.1 of our Quarterly Report on Form 10-Q filed November 14, 2022).
10.1.2	Third Amendment to Amended and Restated Senior Secured Credit Agreement dated as of March 28, 2024, by and among Halcón Holdings, LLC, as borrower, Macquarie Bank Limited, as administrative agent and the lenders party hereto, the guarantors party hereto and Battalion Oil Corporation, as holdings (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed March 28, 2024).
10.2	Warrant Agreement, dated October 8, 2019, by and between Halcón Resources Corporation and Broadridge Corporate Issuer Solutions, Inc., as warrant agent (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed October 8, 2019).
10.3	Registration Rights Agreement, dated October 8, 2019, by and among Halcón Resources Corporation and each of the parties thereto, as investors (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed October 8, 2019).
10.3.1	First Amendment to Registration Rights Agreement dated March 28, 2023, by and among Battalion Oil Corporation and each of the parties thereto, as investors (Incorporated by reference to Exhibit 10.3.1 of our Annual Report on Form 10-K filed March 30, 2023).
10.3.2	Second Amendment to Registration Rights Agreement dated September 6, 2023, by and among Battalion Oil Corporation and each of the parties thereto, as investors (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed September 7, 2023).
10.3.3	Third Amendment to Registration Rights Agreement dated December 15, 2023, by and among Battalion Oil Corporation and each of the other parties thereto, as investors (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed December 18, 2023).
10.3.4	Fourth Amendment to Registration Rights Agreement dated March 27, 2024, by and among Battalion Oil Corporation and each of the other parties thereto, as investors. (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed March 28, 2024).
10.4†	Battalion Oil Corporation 2020 Long-Term Incentive Plan, effective as of January 1, 2020 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed January 31, 2020).
10.4.1†	Amendment No. 1 to the Battalion Oil Corporation 2020 Long-Term Incentive Plan, effective as of June 8, 2021 (Incorporated by reference to Exhibit 10.1.1 of our Current Report on Form 8-K filed June 14, 2021).
10.5†	Employment Agreement between Richard H. Little and Battalion Oil Corporation effective as of January 28, 2020 (Incorporated by reference to Exhibit 10.5 of our Annual Report on Form 10-K filed March 25, 2020).
10.6†	Employment Agreement between Daniel P. Rohling and Battalion Oil Corporation effective as of January 28, 2020 (Incorporated by reference to Exhibit 10.7 of our Annual Report on Form 10-K filed March 25, 2020).

10.7†	Offer Letter with Kristen McWatters dated January 20, 2023 (Incorporated by reference to Exhibit 10.7 of our Annual Report on Form 10-K filed March 30, 2023).
10.8	Purchase Agreement (Series A Preferred Stock), dated March 28, 2023, by and among Battalion Oil Corporation and each of the purchasers set forth on Schedule A thereto (Incorporated by reference to Exhibit 10.8 of our Annual Report on Form 10-K filed March 30, 2023).
10.9	Purchase Agreement (Series A-1 Preferred Stock), dated September 6, 2023, by and among Battalion Oil Corporation and each of the purchasers set forth on Schedule A thereto (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed September 7, 2023).
10.10	Purchase Agreement (Series A-2 Preferred Stock), dated December 15, 2023, by and among Battalion Oil Corporation and each of the purchasers set forth on Schedule A thereto (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed December 18, 2023).
10.11	Purchase Agreement (Series A-3 Preferred Stock), dated March 27, 2024, by and among Battalion Oil Corporation and each of the purchasers set forth on Schedule A thereto. (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed March 28, 2024).
10.12†	Material Terms of Employment Arrangements between Walter R. Mayer and Battalion Oil Corporation (Incorporated by reference to Exhibit 10.9 of our Annual Report Amendment on Form 10-K/A filed April 28, 2023).
10.13†	Form of Nonqualified Stock Option Award Agreement (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed January 31, 2020).
10.14†	Form of Base Restricted Stock Unit Award Agreement (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed January 31, 2020).
10.15†	Form of Performance-Based Restricted Stock Unit Award Agreement (Incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed January 31, 2020).
10.16†	Form of M&A Restricted Stock Unit Award Agreement (Incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K filed January 31, 2020).
21.1*	List of Subsidiaries of Battalion Oil Corporation
31*	Sarbanes-Oxley Section 302 certification of Principal Executive Officer and Principal Financial Officer
32*	Sarbanes-Oxley Section 906 certification of Principal Executive Officer and Principal Financial Officer
97*	Incentive Compensation Recoupment Policy
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* *Attached hereto.*

† *Indicates management contract or compensatory plan or arrangement.*

The registrant has not filed with this report copies of the instruments defining rights of all holders of long-term debt of the registrant and its consolidated subsidiaries based upon the exception set forth in Item 601(b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the SEC upon request.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BATTALION OIL CORPORATION

Date: March 29, 2024

By: /s/ MATTHEW B. STEELE

Matthew B. Steele
Chief Executive Office
(Principal Executive Officer and Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ MATTEW B. STEELE Matthew B. Steele	Director and Chief Executive Officer	March 29, 2024
/s/ JONATHAN BARRETT Jonathan Barrett	Chairman of the Board	March 29, 2024
/s/ DAVID CHANG David Chang	Director	March 29, 2024
/s/ GREGORY HINDS Gregory Hinds	Director	March 29, 2024
/s/ AJAY JEGADEESAN Ajay Jegadeesan	Director	March 29, 2024
/s/ WILLIAM ROGERS William Rogers	Director	March 29, 2024

Exhibit 21.1

Subsidiaries of the Registrant

Subsidiary	**State of Incorporation or Organization**
Battalion Energy Holdings, LLC.	Delaware
Battalion Oil Management, Inc.	Delaware
Halcón Energy Properties, Inc.	Delaware
Halcón Field Services, LLC	Delaware
Halcón Holdings, LLC	Delaware
Halcón Operating Co., Inc.	Texas
Halcón Permian, LLC	Delaware
Wink Amine Treater Holdings, LLC	Texas

Exhibit 31

CERTIFICATION FOR FORM 10-K

I, Matthew B. Steele, certify that:

1. I have reviewed this Annual Report on Form 10-K of Battalion Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

BATTALION OIL CORPORATION

March 29, 2024

By: /s/ Matthew B. Steele
Name: Matthew B. Steele
Title: Chief Executive Officer
(Principal Executive Officer and Principal Financial Officer)

Exhibit 32

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002
(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), Matthew B. Steele, Chief Executive Officer of Battalion Oil Corporation, (the "***Company***"), each hereby certifies that, to the best of his knowledge:

(1) The Company's Annual Report on Form 10-K for the year ended December 31, 2023 (the " ***Report***") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 29, 2024

/s/ Matthew B. Steele
Matthew B. Steele
Chief Executive Officer
(Principal Executive Officer and Principal Financial Officer)

This certification accompanies this Form 10-K and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, or otherwise subject to the liability of that Section.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 97

INCENTIVE COMPENSATION RECOUPMENT POLICY
(the "*Policy*")

1. Recoupment. If Battalion Oil Corporation (the "***Company***") is required to prepare a Restatement, the Company's board of directors (the "***Board***") shall, unless the Board's Compensation Committee determines it to be Impracticable, take reasonably prompt action to recoup all Recoverable Compensation from any Covered Person. Subject to applicable law, the Board may seek to recoup Recoverable Compensation by requiring a Covered Person to repay such amount to the Company; by adding "*holdback*" or deferral policies to incentive compensation; by adding post-vesting "*holding*" or "*no transfer*" policies to equity awards; by set-off of a Covered Person's other compensation; by reducing future compensation; or by such other means or combination of means as the Board, in its sole discretion, determines to be appropriate. This Policy is in addition to (and not in lieu of) any right of repayment, forfeiture or off-set against any Covered Person that may be available under applicable law or otherwise (whether implemented prior to or after adoption of this Policy). The Board may, in its sole discretion and in the exercise of its business judgment, determine whether and to what extent additional action is appropriate to address the circumstances surrounding any Restatement to minimize the likelihood of any recurrence and to impose such other discipline as it deems appropriate.

2. Administration of Policy. The Board shall have full authority to administer, amend or terminate this Policy. The Board shall, subject to the provisions of this Policy, make such determinations and interpretations and take such actions in connection with this Policy as it deems necessary, appropriate or advisable. All determinations and interpretations made by the Board shall be final, binding and conclusive. The Board may delegate any of its powers under this Policy to the Compensation Committee of the Board or any subcommittee or delegate thereof.

3. Acknowledgement by Executive Officers. The Board shall provide notice to and seek written acknowledgement of this Policy, in the form attached hereto as Exhibit A; from each Executive Officer; provided that the failure to provide such notice or obtain such acknowledgement shall have no impact on the applicability or enforceability of this Policy.

4. No Indemnification. Notwithstanding the terms of any of the Company's organizational documents, any corporate policy or any contract, no Covered Person shall be indemnified against the loss of any Recoverable Compensation.

5. Disclosures. The Company shall make all disclosures and filings with respect to this Policy and maintain all documents and records that are required by the applicable rules and forms of the U.S. Securities and Exchange Commission (the "***SEC***") (including, without limitation, Rule 10D-1 promulgated under the Securities Exchange Act of 1934, as amended (the "***Exchange Act***")) and any applicable exchange listing standard.

6. Definitions. In addition to terms otherwise defined in this Policy, the following terms, when used in this Policy, shall have the following meanings:

"***Applicable Period***" means the three completed fiscal years preceding the earlier of: (i) the date that the Board, a committee of the Board, or the officer or officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare a Restatement; or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare a Restatement.

"***Covered Person***" means any person who receives Recoverable Compensation.

"***Executive Officer***" includes the Company's president, principal financial officer, principal accounting officer (or if there is no such accounting officer, the controller), any vice-president of the Company in charge of a principal business unit, division, or function (such as sales, administration, or finance), any other officer who performs a policy-making function, or any other person (including any executive officer of the Company's affiliates) who performs similar policy-making functions for the Company.

"***Financial Reporting Measure***" means a measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements (including "*non-GAAP*" financial measures, such as those appearing in earnings releases), and any measure that is derived wholly or in part from such measure. Examples of Financial Reporting Measures include measures based on: revenues, net income, operating income, financial ratios, EBITDA, liquidity measures, return measures (such as return on assets), profitability of one or more segments, sales per square foot, same store sales, revenue per user, and cost per employee. Stock price and total shareholder return ("***TSR***") also are Financial Reporting Measures.

"***Impracticable***" means, after exercising a normal due process review of all the relevant facts and circumstances and taking all steps required by Exchange Act Rule 10D-1 and any applicable exchange listing standard, the Compensation Committee determines that recovery of the Incentive-Based Compensation is impracticable because: (i) it has determined that the direct expense that the Company would pay to a third party to assist in recovering the Incentive-Based Compensation would exceed the amount to be recovered; (ii) it has concluded that the recovery of the Incentive-Based Compensation would violate home country law adopted prior to November 28, 2022; or (iii) it has determined that the recovery of Incentive-Based Compensation would cause a tax-qualified retirement plan, under which benefits are broadly available to the Company's employees, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder.

"***Incentive-Based Compensation***" includes any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure; however it does not include: (i) base salaries; (ii) discretionary cash bonuses; (iii) awards (either cash or equity) that are based upon subjective, strategic or operational standards; and (iv) equity awards that vest solely on the passage of time.

"***Received***" – Incentive-Based Compensation is deemed "*Received*" in any Company fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that period.

“***Recoverable Compensation***” means all Incentive-Based Compensation (calculated on a pre-tax basis) Received after December 1, 2023, by a person: (i) after beginning service as an Executive Officer; (ii) who served as an Executive Officer at any time during the performance period for that Incentive-Based Compensation; (iii) while the Company had a class of securities listed on a national securities exchange or national securities association; and (iv) during the Applicable Period, that exceeded the amount of Incentive-Based Compensation that otherwise would have been Received had the amount been determined based on the Financial Performing Measures, as reflected in the Restatement. With respect to Incentive-Based Compensation based on stock price or TSR, when the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in an accounting restatement, the amount must be based on a reasonable estimate of the effect of the Restatement on the stock price or TSR upon which the Incentive-Based Compensation was received.

“***Restatement***” means an accounting restatement of any of the Company’s financial statements due to the Company’s material noncompliance with any financial reporting requirement under U.S. securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements (often referred to as a “*Big R*” restatement), or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (often referred to as a “*little r*” restatement). A Restatement does not include situations in which financial statement changes did not result from material non-compliance with financial reporting requirements, such as, but not limited to retrospective: (i) application of a change in accounting principles; (ii) revision to reportable segment information due to a change in the structure of the Company’s internal organization; (iii) reclassification due to a discontinued operation; (iv) application of a change in reporting entity, such as from a reorganization of entities under common control; (v) adjustment to provision amounts in connection with a prior business combination; and (vi) revision for stock splits, stock dividends, reverse stock splits or other changes in capital structure.

Adopted by the Board of Directors on November 28, 2023.

BATTALION OIL CORPORATION

ACKNOWLEDGMENT AND CONSENT TO
INCENTIVE COMPENSATION RECOUPMENT POLICY

The undersigned has received a copy of the Incentive Compensation Recoupment Policy (the "***Policy***") adopted by Battalion Oil Corporation (the "***Company***").

For good and valuable consideration, the receipt of which is acknowledged, the undersigned agrees to the terms of the Policy and agrees that compensation received by the undersigned may be subject to reduction, cancellation, forfeiture and/or recoupment to the extent necessary to comply with the Policy, notwithstanding any other agreement to the contrary. The undersigned further acknowledges and agrees that the undersigned is not entitled to indemnification in connection with any enforcement of the Policy and expressly waives any rights to such indemnification under the Company's organizational documents or otherwise.

Date: ______________________ Signature: ____________________________

Name: ____________________________

Title: ____________________________

Exhibit 99.1

February 21, 2024

Mr. Russell W. Greco
Battalion Oil Corporation
820 Gessner Road, Suite 1100
Houston, Texas 77024

Dear Mr. Greco:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2023, to the Battalion Oil Corporation (Battalion) interest in certain oil and gas properties located in Oklahoma and Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Battalion. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Battalion's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Battalion interest in these properties, as of December 31, 2023, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	18,497.6	9,732.9	71,506.5	802,162.4	462,965.1
Proved Developed Non-Producing	415.0	43.6	287.7	19,426.2	11,701.6
Proved Undeveloped	15,882.1	5,165.3	40,471.9	405,086.6	139,272.5
Total Proved	34,794.7	14,941.8	112,266.2	1,226,675.1	613,939.2

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Battalion's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Battalion's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2023. For oil and NGL volumes, the average West Texas Intermediate spot price of $78.21 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.637 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $77.05 per barrel of oil, $21.47 per barrel of NGL, and $1.254 per MCF of gas.

Operating costs used in this report are based on operating expense records of Battalion. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into midstream-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Battalion are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Battalion and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for artificial lift installations, new development wells, production equipment, and facilities. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Battalion's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Battalion interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Battalion receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Battalion, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Battalion, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Neil H. Little, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 9 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

By: /s/ Neil H. Little
Neil H. Little, P.E. 117966
Vice President

Date Signed: February 21, 2024

By: /s/ Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: February 21, 2024

NHL:JDK

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.